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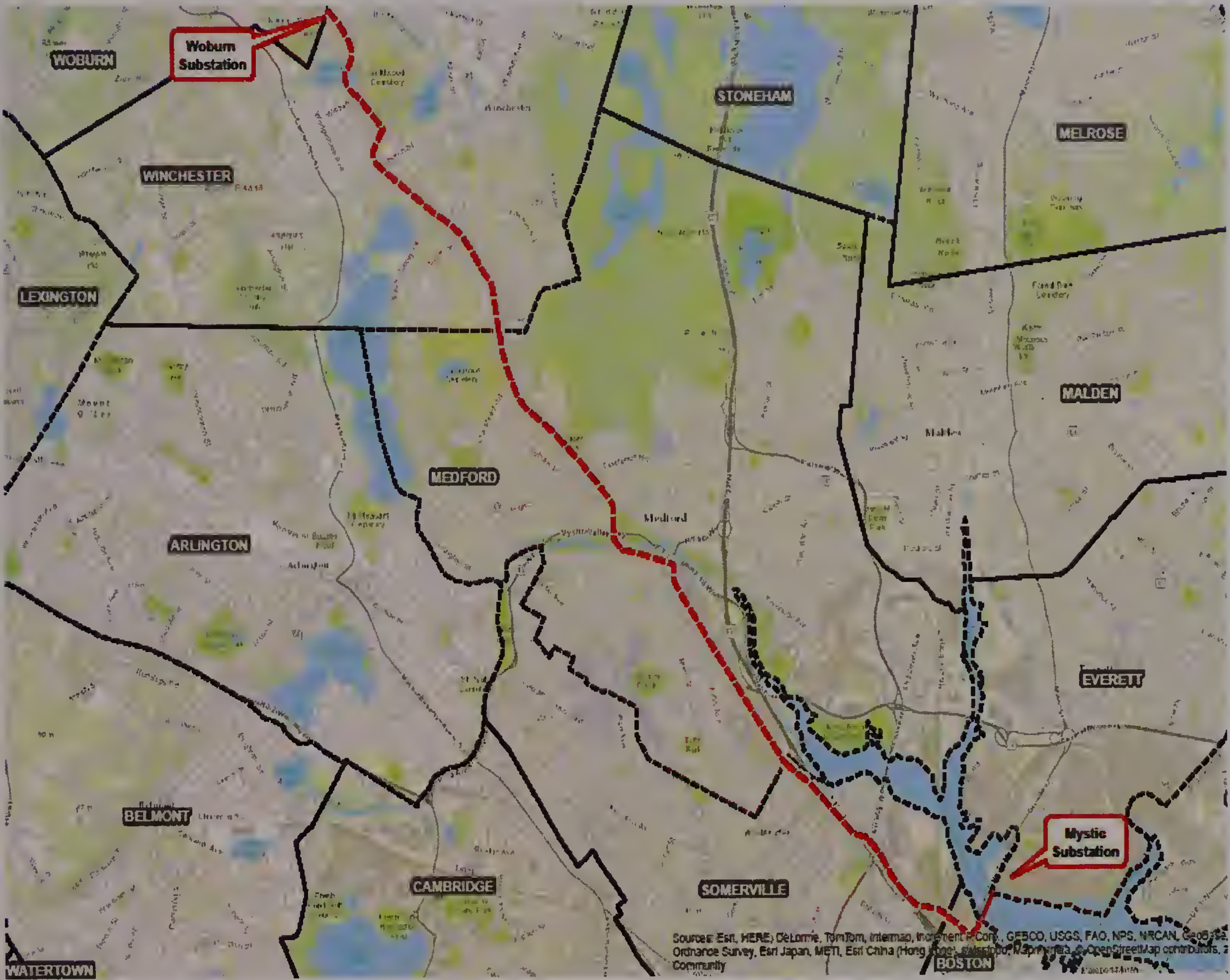
Mystic-Woburn Transmission Project

Analysis to Support Petition before the Massachusetts Energy Facilities Siting Board
Volume III - Appendices


Woburn Substation
WOBURN
WINCHESTER
STONEHAM
MELROSE
LEXINGTON
MALDEN
MEDFORD
ARLINGTON
EVERETT
BELMONT
Mystic Substation
CAMBRIDGE
SOMERVILLE
WATERTOWN
BOSTON

Sources: Esri, HERE, DeLorme, TomTom, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, a
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PREPARED FOR:

EVERSOURCE

IN ASSOCIATION WITH:

POWER ENGINEERS
Environmental Services Div.

Tighe&Bond

KEEGAN WERLIN LLP

May 2015

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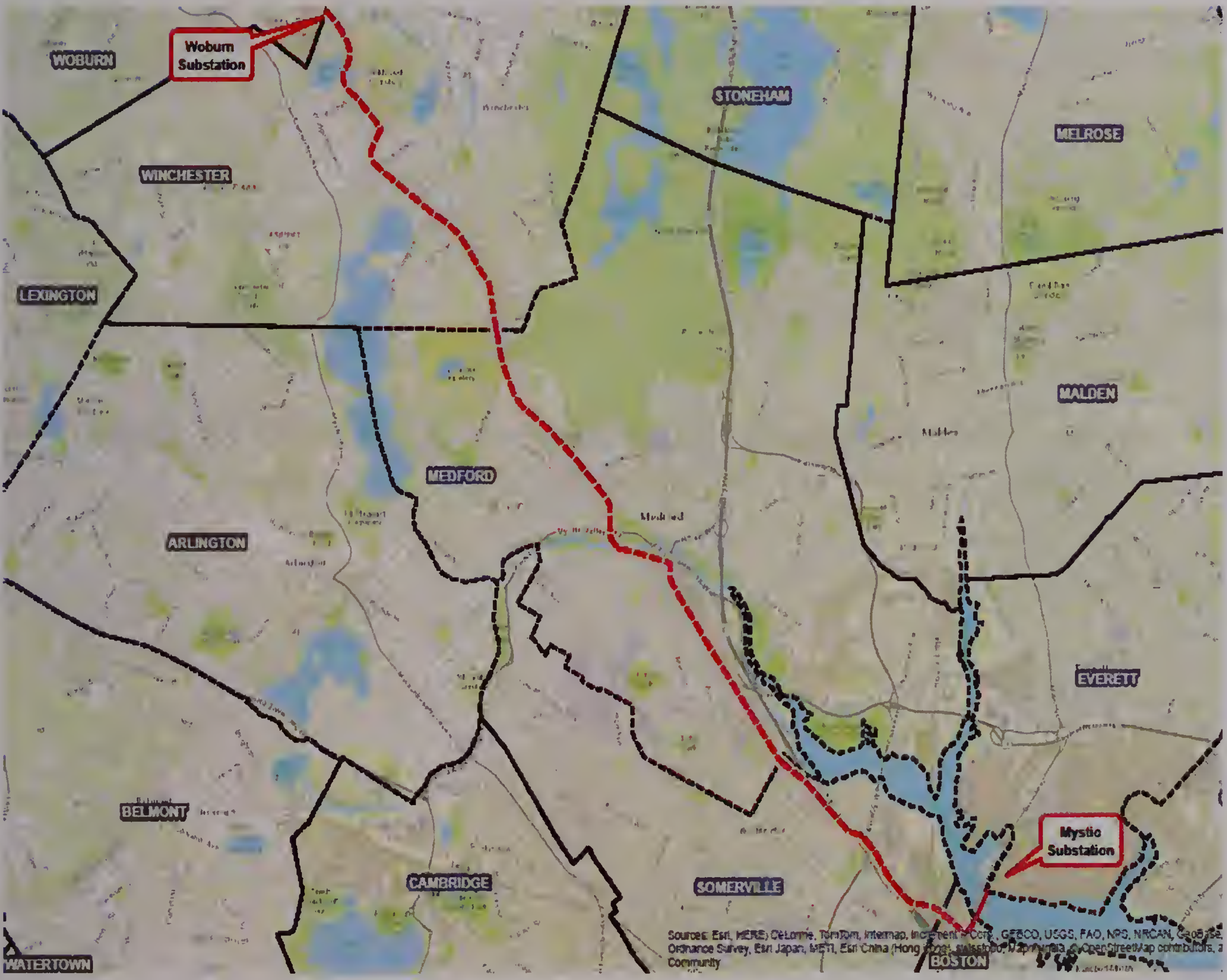
Mystic-Woburn Transmission Project

Analysis to Support Petition before the Massachusetts Energy Facilities Siting Board

Volume III - Appendices



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Environmental Services Div.

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KEEGAN WERLIN LLP

May 2015

APPENDIX INDEX

APPENDIX 1-1 - Mystic to Woburn Transmission Project Environmental Notification Form

APPENDIX 2-1 - Greater Boston Area Updated Transmission Needs Assessment (January 30, 2015) (CEII Redacted)

APPENDIX 2-2 - Greater Boston Preferred Solution, Planning Advisory Committee (February 18, 2015) (CEII Redacted)

APPENDIX 4-1 - Analysis of Non-Transmission Alternatives ("NTA") to the Mystic to Woburn Project (May 1, 2015)

APPENDIX 6-1 - Electric and Magnetic Field (EMF) Analysis for the Mystic to Woburn 211-514x and 211-514y 115 kV Transmission Lines (March 6, 2015)

APPENDIX 1-1

Mystic to Woburn Transmission Project

Environmental Notification Form

Woburn, Winchester, Medford,
Somerville, Everett, and Boston,
Massachusetts

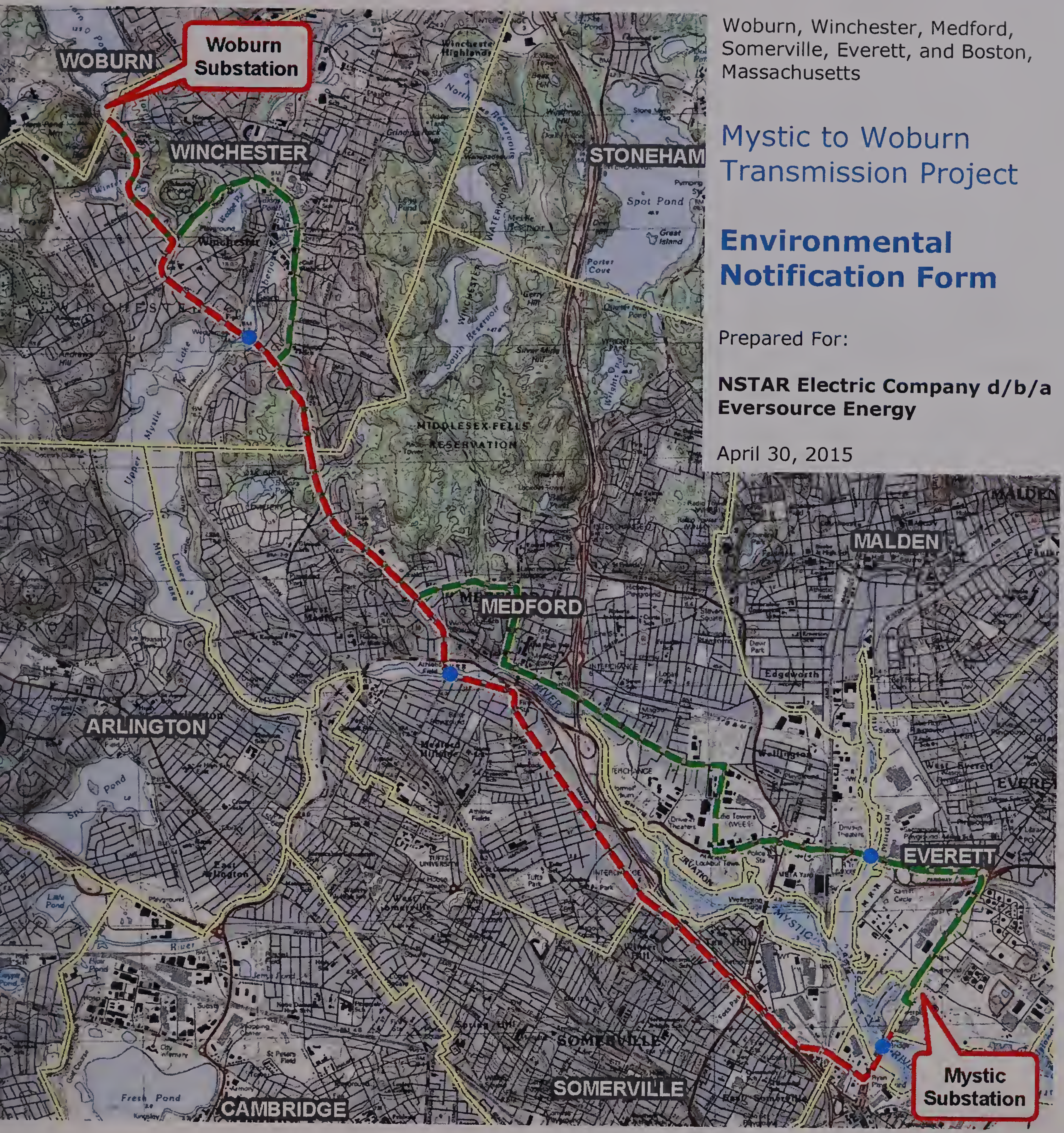
Mystic to Woburn Transmission Project

Environmental Notification Form

Prepared For:

**NSTAR Electric Company d/b/a
Eversource Energy**

April 30, 2015


WOBURN
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N0998-11-04
April 30, 2015

Secretary Matthew A. Beaton
Executive Office of Energy and Environmental Affairs
Attn: MEPA Office
100 Cambridge Street, Suite 900
Boston, MA 02114

Re: **Environmental Notification Form (ENF)**
Mystic to Woburn Transmission Project
Woburn, Winchester, Medford, Somerville, Everett, and Boston, MA

Dear Secretary Beaton:

On behalf of NSTAR Electric Company d/b/a Eversource Energy ("Eversource" or "Company"), Tighe & Bond is submitting this Environmental Notification Form (ENF) for the Mystic to Woburn Transmission Project located in Woburn, Winchester, Medford, Somerville, Everett, and Charlestown (Boston), Massachusetts. The project triggers review under the Massachusetts Environmental Policy Act (MEPA) with an ENF per:

- 301 CMR 11.03(1)(b)(3): Conversion of land held for natural resources purposes in accordance with Article 97 of the Amendments to the Constitution of the Commonwealth to any purpose not in accordance with Article 97.
- 301 CMR 11.03(3)(b)1.f.: Alteration of one half or more acres of any other wetlands (Riverfront Area, Bordering Land Subject to Flooding, and potentially Land Under Water).

This ENF describes activities necessary to install approximately 7.7 miles of new underground electric transmission line, parallel to an existing underground electric transmission line, between the Eversource Woburn and Mystic Substations. This project is needed to improve the reliability of the electric grid in the Greater Boston area, and specifically to address thermal overloads in the existing line.

The attached ENF and narrative includes detailed project information including a comprehensive alternatives analysis, and a discussion of impacts and mitigation measures for the MEPA review thresholds triggered.

Please notice this ENF in the Environmental Monitor to be published on May 6, 2015. Should you have any questions or require additional information, please contact Tracy J. Adamski at (413) 572-3256 or me at (413) 875-1312.

Very truly yours,

TIGHE & BOND, INC.

Daniel P. Rukakoski, PWS
Principal Environmental Scientist - Associate

Enclosures: Environmental Notification Form and Attachments

Copy: Refer to the Distribution and Circulation List provided in Attachment C
Kevin McCune, Eversource Energy
Michael Zylich, Eversource Energy
David Velez, Eversource Energy
David Rosenweig, Keegan Werlin LLP

\\SRV\Projects\N\N0998 NSTAR\Woburn to Mystic\Permitting - ENF\FINAL\02_Cover Letter.docx

53 Southampton Road • Westfield, MA 01085-5308 • Tel 413.562.1600 • Fax 413.562.5317

Environmental Notification Form

Attachments

Attachment A: Project Description

Attachment B: Figures

- Figure 1: Project Location
- Figure 1A: Candidate Route Alternatives
- Figure 2: Existing Conditions
- Figure 3: ACEC and Rare Species
- Figure 4: Historical Resources
- Figure 5: Water Resources
- Figure 6: Impaired Waterbodies
- Figure 7: Article 97 Lands
- Figure 8: Aberjona River Crossing South of Bridge Trenchless Alternative
- Figure 9: Aberjona River Crossing Trenched Alternative
- Figure 10: Aberjona River Crossing North of Bridge Trenchless Alternative
- Figure 11: Mystic River Crossing Trenchless Alternative

Attachment C: Distribution List

Attachment D: List of Permits and Approvals

Attachment E: Excerpts from Massachusetts Year 2012 Integrated List of Waters

Commonwealth of Massachusetts
Executive Office of Energy and Environmental Affairs
Massachusetts Environmental Policy Act (MEPA) Office

Environmental Notification Form

For Office Use Only

EEA#: ________________

MEPA Analyst: ______________

The information requested on this form must be completed in order to submit a document electronically for review under the Massachusetts Environmental Policy Act, 301 CMR 11.00.

Project Name: Mystic to Woburn Transmission Project

Street Address: Multiple streets in Woburn, Winchester, Medford, Somerville, Everett, and Boston

Municipality: Woburn, Winchester, Medford, Somerville, Everett, Boston	Watershed: Boston Harbor (Mystic River)
Universal Transverse Mercator Coordinates: North End: 322927.27 4703298.27 South End: 329820.18 4695411.22	Latitude: Longitude: North End: 42 27' 42" N -71 09' 20" W South End: 42 23' 33" N -71 04' 04" W
Estimated commencement date: April 2017	Estimated completion date: December 2018
Project Type: Utility	Status of project design: 30 %complete

Proponent: NSTAR Electric d/b/a Eversource Energy

Street Address: One NSTAR Way, NE250

Municipality: Westwood	State: MA	Zip Code: 02090

Name of Contact Person: Daniel Rukakoski

Firm/Agency: Tighe & Bond	Street Address: 53 Southampton Road

Municipality: Westfield	State: MA	Zip Code: 01085
Phone: 413-875-1312	Fax: 413-562-5317	E-mail: DPRukakoski@TigheBond.com

Does this project meet or exceed a mandatory EIR threshold (see 301 CMR 11.03)?
☐Yes ☒No

If this is an Expanded Environmental Notification Form (ENF) (see 301 CMR 11.05(7)) or a Notice of Project Change (NPC), are you requesting:

a Single EIR? (see 301 CMR 11.06(8))	☐Yes ☒No
a Special Review Procedure? (see 301CMR 11.09)	☐Yes ☒No
a Waiver of mandatory EIR? (see 301 CMR 11.11)	☐Yes ☒No
a Phase I Waiver? (see 301 CMR 11.11)	☐Yes ☒No

(Note: Greenhouse Gas Emissions analysis must be included in the Expanded ENF.)

Which MEPA review threshold(s) does the project meet or exceed (see 301 CMR 11.03)? 301 CMR 11.03(1)(b)(3): conversion of land held for natural resources purposes in accordance with Article 97 of the Amendments to the Constitution of the Commonwealth to any purpose not in accordance with Article 97; and 301 CMR 11.03(3)(b)1.f.: Alteration of one half or more acres of any other wetlands (will include Riverfront Area and Bordering Land Subject to Flooding and, depending on project alternative selected, may include Land Under Water).

Which State Agency Permits will the project require? Ch. 91 Waterways authorization (Determination of Applicability), 401 Water Quality Certificate, and potentially Utility-Related Abatement Measures ("URAM") from MassDEP; DPU Approval under MGL c.164 Sec 72 and M.G.L. c. 40A, s. 3; MassDOT Highway Access Permit; a Construction and Access Permit and an Article 97 long term easement from the DCR; MBTA Access Permit; MWRA Section 8(m) Permit; approvals from local conservation commissions under the Massachusetts Wetland Protection Act. A full list of permits is included in Attachment D.

Identify any financial assistance or land transfer from an Agency of the Commonwealth, including the Agency name and the amount of funding or land area in acres: Department of Conservation and Recreation (DCR) – up to 0.5 acres – Article 97 access agreements

Summary of Project Size & Environmental Impacts	**Existing**	**Change**	**Total**
LAND			
Total site acreage	~115 acres		
New acres of land altered		~ 4.5 acres	
Acres of impervious area	0	0	0
Square feet of new bordering vegetated wetlands alteration		0	
Square feet of new other wetland alteration		~23,200 sf	
Acres of new non-water dependent use of tidelands or waterways		0	
STRUCTURES			
Gross square footage	0	0	0
Number of housing units	0	0	0
Maximum height (feet)	0	0	0
TRANSPORTATION			
Vehicle trips per day	0	0	0
Parking spaces	0	0	0
WASTEWATER			
Water Use (Gallons per day)	0	0	0
Water withdrawal (GPD)	0	0	0
Wastewater generation/treatment (GPD)	0	0	0
Length of water mains (miles)	0	0	0
Length of sewer mains (miles)	0	0	0

Has this project been filed with MEPA before?
☐ Yes (EEA #__________) ☒No

Has any project on this site been filed with MEPA before?
☐ Yes (EEA #__________) ☒No

1 The site acreage reported here is the approximate land area contained within the substations, and assumed 40 foot wide roadway ROWs along the project route.
2 New acres of land altered includes the direction drilling construction at the upper Mystic River crossing and potential impacts at the Aberjona River crossing. The additional 3.5 acres are temporary impacts associated with an assumed 4 foot wide work area for the installation of underground utilities within existing roadways.
3 No change in impervious surfaces is anticipated
4 New other wetland alteration includes temporary impacts in Riverfront Area, BLSF and Land Under Water.
5 The number of vehicles traveling to and from the substations will not change as a result of the Project. Peak construction vehicle trips would occur during trench soil hauling, which would be on average 8 trips per hour for 8-hour shifts or 64 total trips.

GENERAL PROJECT INFORMATION – all proponents must fill out this section

PROJECT DESCRIPTION:

The proposed Mystic to Woburn Transmission Project ("Project") proposed by NSTAR Electric d/b/a Eversource Energy ("Proponent" or "Eversource") is the installation of a new 115 kV underground electric transmission line between the existing Eversource Woburn Substation in Woburn and the Mystic Substation in Everett. The Project is located in the municipalities of Woburn, Winchester, Medford, Somerville, Everett and Charlestown (Boston). The project also involves upgrades at the Eversource Woburn and Mystic Substations. The Project is needed to relieve potential overloads on the existing underground Line. The new underground line (the "New Line") will operate in parallel with and increase the capacity of the existing transmission line. Figure 1 provides an overview of the Preferred Route, as well as the locations of the Mystic and Woburn substations. Figure 2 shows the EFSB Preferred and Noticed Alternative routes and existing conditions within the project area.

The Project purpose is to improve the reliability of electric transmission within the Greater Boston area and address thermal overloads within the existing electric transmission line. In combination with other planned Greater Boston Area transmission upgrades, the Project provides a system with substantial flexibility to accommodate load growth.

The Project (substation to substation) will consist of 7.7 miles of new underground line to be operated in parallel with the existing underground Line. This new line will be a high pressure fluid filled pipe type cable ("HPFF-PTC") system consisting of three stranded and insulated copper cables installed in a sealed and 8-inch steel pipe filled with dielectric fluid.

The 8-inch steel pipe, along with two-inch diameter polyvinyl chloride ("PVC") conduits for relay and communication cables, will be installed in a nominal 24-inch wide by 60-inch deep trench. Manholes for pulling in and splicing cables, line testing, and maintenance will be installed at spacing intervals of approximately 2,000 to 2,400 linear feet. Preliminary estimates indicate approximately 17 manholes will need to be installed for the system.

The Project also includes the installation of a new series reactor at Woburn Substation to balance power flows between the existing and new lines, and modifications to the line termination connections at Mystic Substation. Construction in the Woburn Substation will include construction of foundations for the series reactor and trenching for HPFF-PTC installation.

Additional project information including an alternatives analysis and assessment of impacts and proposed mitigation measures is included in Attachment A.

AREAS OF CRITICAL ENVIRONMENTAL CONCERN:

Is the project within or adjacent to an Area of Critical Environmental Concern?

☐Yes (Specify____________________________________)
☒No (See Figure 3)

if yes, does the ACEC have an approved Resource Management Plan? N/A
If yes, describe how the project complies with this plan.

____

Will there be stormwater runoff or discharge to the designated ACEC? N/A;
If yes, describe and assess the potential impacts of such stormwater runoff/discharge to the designated ACEC. ____

RARE SPECIES:

Does the project site include Estimated and/or Priority Habitat of State-Listed Rare Species? (see http://www.mass.gov/dfwele/dfw/nhesp/regulatory_review/priority_habitat/priority_habitat_home.htm)

☒Yes ☐No

The Project crosses one area mapped by NHESP as Priority Habitat, PH 1448. The proposed work in this area will be the installation of a new underground electric transmission line within an existing easement that contains the existing electric transmission line. The Proponent will consult with NHESP to discuss any requirements to assess this area and mitigate any potential impact. Priority Habitat 1448 also abuts the Project for approximately 670 Linear feet along the Winter Pond side of Woodside Road in Winchester but no impacts to Habitat are expected because work is within the existing paved roadway. Figure 3 shows the extent of Priority and Estimate Habitats with respect to the Routes. Mitigation measures consist of construction period erosion and sediment controls and limiting work to the existing road extent to avoid impacts to Habitat. Furthermore, per 321 CMR 10.14 (6), *construction, repair, replacement or maintenance of … utility lines, … within existing paved areas and lawfully developed and maintained lawns or landscaped areas, provided there is no expansion of such existing paved, lawn and landscaped areas* are exempt from the requirements of 321 CMR 10.18 through 10.23 and therefore the work in Woodside Road does not require review by the Division of Fisheries and Wildlife.

HISTORICAL /ARCHAEOLOGICAL RESOURCES:

Does the project site include any structure, site or district listed in the State Register of Historic Place or the inventory of Historic and Archaeological Assets of the Commonwealth?

☒Yes ☐No

The Project passes through National and/or Local Historic Districts with numerous individually registered historic residential homes or properties. There are Individually Inventoried historic properties abutting the Project Route. As the Project will include installation of underground utilities and work within existing substations, no impact to historic resources is anticipated. Figure 4 shows the extent of historical and archeological resources. Further detail on Historical and Archeological Resources is included in the Project Description in Attachment A.

If yes, does the project involve any demolition or destruction of any listed or inventoried historic or archaeological resources? ☐Yes ☒No

WATER RESOURCES:

Is there an Outstanding Resource Water (ORW) on or within a half-mile radius of the project site?

☒Yes ☐No

if yes, identify the ORW and its location. Figure 5 shows the locations of Outstanding Resource Waters in relation to the Project. Using GIS mapping, there are three Certified Vernal Pools located within a half-mile radius of the Project, as follows:

CVP Number	Criteria	Certified Date
3864	Fairy Shrimp	3/21/2006
1594	Fairy Shrimp	7/29/1998
1595	Fairy Shrimp	7/29/1998

The northwestern end of the project is located within an area designated as an Outstanding Resource Water for the public water supply associated with Horn Pond, which historically served as surplus water supply for the City of Woburn.

No impact to resource areas is anticipated.

(NOTE: Outstanding Resource Waters include Class A public water supplies, their tributaries, and bordering wetlands; active and inactive reservoirs approved by MassDEP; certain waters within Areas of Critical Environmental Concern, and certified vernal pools. Outstanding resource waters are listed in the Surface Water Quality Standards, 314 CMR 4.00.)

Are there any impaired water bodies on or within a half-mile radius of the project site? ☒Yes ☐No ; if yes, identify the water body and pollutant(s) causing the impairment:

Based on GIS maps created using the Project route and the Final Massachusetts Year 2012 Integrated List of Waters, a number of impaired waterbodies are within a half-mile radius of the Project Preferred Route and the Noticed alternative route analyzed. Figure 6 shows the names and locations of these waterbodies. The following table summarizes the name of the waterbody and category. Attachment E includes a copy of excerpts from the 2012 Integrated List of Waters showing the pollutants of concern.

Segment ID	Waterbody Name	Category
MA71-01	Aberjona River	5
MA71-02	Mystic River	5
MA71-05	Malden River	5
MA71-13	Unnamed Tributary	5
MA71047	Winter Pond	5
MA71045	Wedge Pond	5
MA71019	Horn Pond	5
MA71043	Upper Mystic Lake	5
MA71-03	Mystic River	5
MA71004	Bellevue Pond	3

Is the project within a medium or high stress basin, as established by the Massachusetts Water Resources Commission? ☒Yes ☐No

Based on review of the Water Resources Commission Stressed Basins in Massachusetts report dated December 13, 2001, the upper portion of the Boston Harbor – Mystic River basin is considered High Stress. Due to the quality of maps available showing the basins and associated stress, it is unclear exactly where the High Stress and No Data line is in related to the Project, and therefore we have been conservative by saying yes. However, the Project will not result in water withdrawals.

STORMWATER MANAGEMENT:

Generally describe the project's stormwater impacts and measures that the project will take to comply with the standards found in MassDEP's Stormwater Management Regulations:

This Project consists of installation of an underground electric transmission line and manhole system primarily within existing paved roadways. The proposed Project will be designed to comply with the MassDEP Stormwater Management Policy and Handbook. Surface contours, pavement, vegetation, soils, and other natural and man-made features will be maintained or restored to pre-work conditions. Best Management Practices (BMPs) will be employed to minimize erosion and other potential environmental impacts during construction as further detailed in Attachment A, Project Description.

MASSACHUSETTS CONTINGENCY PLAN:
Has the project site been, or is it currently being, regulated under M.G.L.c.21E or the Massachusetts Contingency Plan? ☒Yes ☐No; if yes, please describe the current status of the site (including Releas Tracking Number (RTN), cleanup phase, and Response Action Outcome classification):

Based on initial research, the Project is located adjacent to no known active MCP sites. Contaminated soils/hazardous materials encountered during construction will be handled, stored, transported and disposed of in accordance with MCP requirements (310 CMR 40), MassDEP policies and all other applicable State and Town regulations. The Proponent will coordinate with an LSP to review release sites identified by the MassDEP in the work area to conduct a pre-construction soil characterization of the route, and to develop a Utility Release Abatement Measure (URAM) plan prior to construction, if required. The URAM would detail procedures to follow for the Contractor installing,the new line in suspected contamination and include information on the correct handling and disposal of any contaminated material.

Is there an Activity and Use Limitation (AUL) on any portion of the project site? Yes ☐ No ☒;
if yes, describe which portion of the site and how the project will be consistent with the AUL:.

Are you aware of any Reportable Conditions at the property that have not yet been assigned an RTN?
☐Yes ☒No; if yes, please describe:____________________________________

SOLID AND HAZARDOUS WASTE:

If the project will generate solid waste during demolition or construction, describe alternatives considere for re-use, recycling, and disposal of, e.g., asphalt, brick, concrete, gypsum, metal, wood: N/A ____________________

(NOTE: Asphalt pavement, brick, concrete and metal are banned from disposal at Massachusetts landfills and waste combustion facilities and wood is banned from disposal at Massachusetts landfills. See 310 CMR 19.017 for the complete list of banned materials.)

Will your project disturb asbestos containing materials? ☐Yes ☒No;
if yes, please consult state asbestos requirements at http://mass.gov/MassDEP/air/asbhom01.htm

Describe anti-idling and other measures to limit emissions from construction equipment: The Contractor will be required to follow MassDEP's anti-idling requirements.

DESIGNATED WILD AND SCENIC RIVER:

Is this project site located wholly or partially within a defined river corridor of a federally designated Wild and Scenic River or a state designated Scenic River? ☐Yes ☒No

Based on review of the January 2015 listing of National Wild and Scenic Rivers, the project site is not located within a defined federal or state designated Wild and Scenic River
http://www.rivers.gov/documents/rivers-table.pdf

If yes, specify name of river and designation:

If yes, does the project have the potential to impact any of the "outstandingly remarkable" resources of a federally Wild and Scenic River or the stated purpose of a state designated Scenic River?
Yes ___ No ___ ; if yes, specify name of river and designation: _____________;
if yes, will the project will result in any impacts to any of the designated "outstandingly remarkable" resources of the Wild and Scenic River or the stated purposes of a Scenic River.

Yes ___ No ___ ;
if yes,describe the potential impacts to one or more of the "outstandingly remarkable" resources or stated purposes and mitigation measures proposed.

ATTACHMENTS:

1. List of all attachments to this document.

Attachment A: Project Narrative
Attachment B: Figures
Figure 1: Project Location
Figure 1A: Candidate Route Alternatives
Figure 2: Existing Conditions
Figure 3: ACEC and Rare Species
Figure 4: Historical Resources
Figure 5: Water Resources
Figure 6: Impaired Waterbodies
Figure 7: Article 97 Lands
Figure 8: Aberjona River Crossing South of Bridge Trenchless Alternative
Figure 9: Aberjona River Crossing Trenched Alternative
Figure 10: Aberjona River Crossing North of Bridge Trenchless Alternative
Figure 11: Mystic River Crossing Trenchless Alternative
Attachment C: Distribution List
Attachment D: List of Permits and Approvals
Attachment E: Excerpts from Massachusetts 2012 Integrated List of Waters

2. U.S.G.S. map (good quality color copy, 8-½ x 11 inches or larger, at a scale of 1:24,000) indicating the project location and boundaries.

Please see Figure 1 in Attachment A.

3.. Plan, at an appropriate scale, of existing conditions on the project site and its immediate environs, showing all known structures, roadways and parking lots, railroad rights-of-way, wetlands and water bodies, wooded areas, farmland, steep slopes, public open spaces, and major utilities.

Please see Figure 2 in Attachment B.

4 Plan, at an appropriate scale, depicting environmental constraints on or adjacent to the project site such as Priority and/or Estimated Habitat of state-listed rare species, Areas of Critical Environmental Concern, Chapter 91 jurisdictional areas, Article 97 lands, wetland resource area delineations, water supply protection areas, and historic resources and/or districts.

Please see Figures 3 through 11 in Attachment B.

5. Plan, at an appropriate scale, of proposed conditions upon completion of project (if construction of the project is proposed to be phased, there should be a site plan showing conditions upon the completion of each phase).

Not applicable – see Project Description

6. List of all agencies and persons to whom the proponent circulated the ENF, in accordance with 301 CMR 11.16(2).

Please see Attachment C.

7. List of municipal and federal permits and reviews required by the project, as applicable.
Please see Attachment D.

LAND SECTION

I. Thresholds / Permits

A. Does the project meet or exceed any review thresholds related to **land** (see 301 CMR 11.03(1)
☒Yes ☐No; if yes, specify each threshold:

11.03 (1)(b)3: Conversion of land held for natural resources purposes in accordance with Article 97 of the Amendments to the Constitution of the Commonwealth to any purpose not in accordance with Article 97.

II. Impacts and Permits

A. Describe, in acres, the current and proposed character of the project site, as follows:

	Existing	Change	Total
Footprint of buildings	N/A	N/A	N/A
Internal roadways	N/A	N/A	N/A
Parking and other paved areas	34 ac	0	34 ac
Other altered areas*	80 ac	0	80 ac
Undeveloped areas	1 ac	0	1 ac
Total: Project Site Acreage	115 ac	0	115 ac

* Electric Substations

B. Has any part of the project site been in active agricultural use in the last five years?
☐Yes ☒No; if yes, how many acres of land in agricultural use (with prime state or locally important agricultural soils) will be converted to nonagricultural use?

C. Is any part of the project site currently or proposed to be in active forestry use?
☐Yes ☒No; if yes, please describe current and proposed forestry activities and indicate whether any part of the site is the subject of a forest management plan approved by the Department of Conservation and Recreation:

D. Does any part of the project involve conversion of land held for natural resources purposes in accordance with Article 97 of the Amendments to the Constitution of the Commonwealth to any purpose not in accordance with Article 97? ☒Yes ☐No; if yes, describe:

Figure 7 shows the extent of the Project and Article 97 lands. The Project crosses DCR-owned land that is subject to Article 97 at the Aberjona River and upper Mystic River crossings, Ginn Field owned by the Town of Winchester, as well as the City of Boston's Ryan's Playground at the lower Mystic River crossing. More detail on potential impacts to Article 97 lands is included in the Project Description in Attachment A.

E. Is any part of the project site currently subject to a conservation restriction, preservation restriction, agricultural preservation restriction or watershed preservation restriction?
☐Yes ☒No; if yes, does the project involve the release or modification of such restriction?
___ Yes ___ No; if yes, describe:

F. Does the project require approval of a new urban redevelopment project or a fundamental change in an existing urban redevelopment project under M.G.L.c.121A? ☐Yes ☒No; if yes, describe:

G. Does the project require approval of a new urban renewal plan or a major modification of an existing urban renewal plan under M.G.L.c.121B? ☐Yes ☒No; if yes, describe:

III. Consistency

A. Identify the current municipal comprehensive land use plan

Title: City of Woburn Master Plan Date: 2004

Title: City of Woburn Open Space and Recreation Plan Date: 2005

Title: Winchester Master Plan – Phase I Report on Housing Neighborhoods Town Center Economic Development Date: April 8, 2010

Title: Medford Five Year Consolidated Plan Date: 2010-2015

Title: Medford Square Master Plan Date: November 2005

Title: Medford Open Space and Recreation Plan Update Date: 2011

Title: Everett Lower Broadway District Master Plan Date: Underway

Title: SomerVision – City of Somerville Comprehensive Plan 2010-2030
Date: April 19, 2012

The Project is consistent with the above listed Plans as it will reinforce the electric transmission system and be constructed within an existing utility facility and existing roadways. This project is part of a greater reliability project to support electricity needs in the Boston area and will support the goals in the numerous community's planning documents.

B. Describe the project's consistency with that plan with regard to:

1) economic development: The Project will support development and redevelopment projects critical to contributing to the future economic well-being of the area

2) adequacy of infrastructure: This project is intended to provide a continued reliable source of electricity to Eversource customers

3) open space impacts: This project will not permanently impact open space. Work is proposed within DCR lands, Ginn Field in Winchester, and City of Boston's Ryan Playground. Impacted areas will be restored upon construction completions. The majority of the work is proposed to be completed in existing disturbed areas (roadways or on existing substation parcels). More detail on potential impacts to open space is presented in the Project Description in Attachment A.

4) compatibility with adjacent land uses: This project will result in conditions prior to construction being restored post construction, and there the final project will not result in a change to land uses or conflict with adjacent land uses.

C. Identify the current Regional Policy Plan of the applicable Regional Planning Agency (RPA)
RPA: Metropolitan Area Planning Council (MAPC)

MAPC has a number of regional plans that apply to economic development, housing, the environment, land use, and the future of the metro area. http://www.mapc.org/

D. Describe the project's consistency with that plan with regard to:

1) economic development: The Project will support development and redevelopment projects critical to contributing to the future economic well-being of the area, consistent with the economic development goals and plans presented in MAPC's numerous documents.

2) adequacy of infrastructure: This project is intended to provide a continued reliable source of electricity to Eversource customers, which supports the numerous economic,

housing, environmental, land use, and metro area goals of MAPC as described in their numerous planning documents.
3) open space impacts: This project will not permanently impact open space. Work is proposed within DCR lands and City of Boston's Ryan Playground. Impacted areas will be restored upon construction completions. The majority of the work is proposed to be completed in existing disturbed areas (roadways or on existing substation parcels), and therefore the project is consistent with MAPC's planning initiatives related to land use and the environment presented on their website.

RARE SPECIES SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **rare species or habitat** (see 301 CMR 11.03(2))? ☐Yes ☒No; if yes, specify, in quantitative terms:

The Project crosses one area mapped by NHESP as Priority Habitat, PH 1448. The proposed work in this area will be the installation of a new underground electric transmission line within an existing easement that contains the existing electric transmission line. The Proponent will consult with NHESP to discuss any requirements to assess this area and mitigate any potential impact. Priority Habitat 1448 also abuts the Project for approximately 670 Linear feet along the Winter Pond side of Woodside Road in Winchester but no impacts to Habitat are expected because work is within the existing paved roadway. Figure 3 shows the extent of Priority and Estimate Habitats with respect to the Routes. Mitigation measures consist of construction period erosion and sediment controls and limiting work to the existing road extent to avoid impacts to Habitat. Furthermore, per 321 CMR 10.14 (6), *construction, repair, replacement or maintenance of … utility lines, … within existing paved areas and lawfully developed and maintained lawns or landscaped areas, provided there is no expansion of such existing paved, lawn and landscaped areas* are exempt from the requirements of 321 CMR 10.18 through 10.23 and therefore the work in Woodside Road does not require review by the Division of Fisheries and Wildlife.

(NOTE: If you are uncertain, it is recommended that you consult with the Natural Heritage and Endangered Species Program (NHESP) prior to submitting the ENF.)

B. Does the project require any state permits related to **rare species or habitat**? ☒Yes ☐No

C. Does the project site fall within mapped rare species habitat (Priority or Estimated Habitat?) in the current Massachusetts Natural Heritage Atlas (attach relevant page)? ☒Yes ☐No.

D. If you answered "No" to all questions A, B and C, proceed to the **Wetlands, Waterways, and Tidelands Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Rare Species section below.

II. Impacts and Permits

A. Does the project site fall within Priority or Estimated Habitat in the current Massachusetts Natural Heritage Atlas (attach relevant page)? ☒Yes ☐No. If yes,

1. Have you consulted with the Division of Fisheries and Wildlife Natural Heritage and Endangered Species Program (NHESP)? ☐ Yes ☒ No; if yes, have you received a determination as to whether the project will result in the "take" of a rare species? ___ Yes ___ No; if yes, attach the letter of determination to this submission.

2. Will the project "take" an endangered, threatened, and/or species of special concern in accordance with M.G.L. c.131A (see also 321 CMR 10.04☐ Yes ☒ No; if yes, provide a summary of proposed measures to minimize and mitigate rare species impacts: Eversource will work with NHESP to identify the species and habitat within the work area and develop construction alternatives to minimize impacts.

3. Which rare species are known to occur within the Priority or Estimated Habitat?

An information request has been prepared for submittal to NHESP under the MESA Process. Feedback from NHESP will identify the rare species known to occur within the Priority Habitat within the work area.

4. Has the site been surveyed for rare species in accordance with the Massachusetts Endangered Species Act? ☐ Yes ☒ No

4. If your project is within Estimated Habitat, have you filed a Notice of Intent or received an Order of Conditions for this project? ☐ Yes ☒ No; if yes, did you send a copy of the Notice of Intent to the Natural Heritage and Endangered Species Program, in accordance with the Wetlands Protection Act regulations? ___ Yes ___ No

B. Will the project "take" an endangered, threatened, and/or species of special concern in accordance with M.G.L. c.131A (see also 321 CMR 10.04)? ☐ Yes ☒ No; if yes, provide a summary of proposed measures to minimize and mitigate impacts to significant habitat:

WETLANDS, WATERWAYS, AND TIDELANDS SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **wetlands, waterways, and tidelands** (see 301 CMR 11.03(3))? ☒Yes ☐No; if yes, specify, in quantitative terms:

B. Does the project require any state permits (or a local Order of Conditions) related to **wetlands, waterways, or tidelands**? ☒Yes ☐No; if yes, specify which permit:

Order of Conditions from Winchester and Medford
Chapter 91 RDA from MassDEP

C. If you answered "No" to both questions A and B, proceed to the **Water Supply Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Wetlands, Waterways, and Tidelands Section below.

II. Wetlands Impacts and Permits

A. Does the project require a new or amended Order of Conditions under the Wetlands Protection Act (M.G.L. c.131A)? ☒Yes ☐No; if yes, has a Notice of Intent been filed? ☐ Yes ☒ No; if yes, list the date and MassDEP file number: ______; if yes, has a local Order of Conditions been issued? ___ Yes ___ No; Was the Order of Conditions appealed? ___ Yes ___ No. Will the project require a Variance from the Wetlands regulations? ___ Yes ___ No.

B. Describe any proposed permanent or temporary impacts to wetland resource areas located on the project site:

As shown on Figure 5 in Attachment B, the new electric transmission line will be installed underground in urban streets, however, the Preferred Route proposes to cross the Mystic River in two locations (in Medford and between Charlestown/Boston and Everett) and the Aberjona River in one location in Winchester. The Company proposes to use an existing spare conduit to route the new line beneath the "lower" Mystic River crossing (between Charlestown/Boston and Everett).
The installation of the new electric transmission line will involve temporary alterations within areas subject to protection under the Wetlands Protection Act and 310 CMR 10.02, including the Riverfront Area, Bordering Land Subject to Flooding, Bank, Land Under Water and 100-foot buffer zone.

The Project will require three river crossings as follows:

- the “lower” Mystic River from Boston to Everett, just south-west of the Mystic Substation
- the “upper” Mystic River in the Town of Medford, from South Street to Winthrop Street; and
- the Aberjona River in the Town of Winchester, where Bacon Street crosses the River.

The “lower” Mystic River crossing will not result in resource area impacts as existing conduit will be used to cross the river. Three options are being considered for the Aberjona River crossing in Winchester, to determine a feasible option that minimizes impacts.

1. Trenchless technology (horizontal directional drill or jack and bore) to the south of Bacon Street (Figure 8)
2. Open cut trenching to the south of Bacon Street (Figure 9)
3. Trenchless technology to the north of Bacon Street (Figure 10)

Under Scenario 1, trenchless technology to the south of Bacon Street (Figure 8), the following temporary impacts to inland wetland resource areas are anticipated in the workspace area:

- Approximately 1,600 square feet of impact to Bordering Land Subject to Flooding
- Approximately 17,100 square feet of impact to Riverfront Area

Under Scenario 2, trenching to the south of Bacon Street (Figure 9), the following temporary impacts to inland wetland resource areas are anticipated in the workspace area:

- Approximately 2,500 square feet of impact to Bordering Land Subject to Flooding
- Approximately 10,000 square feet of impact to Riverfront Area
- Approximately 1,200 square feet of impact to Land Under Water
- Approximately 60 linear feet to Bank

Under Scenario 3, trenchless technology to the north of Bacon Street (Figure 10), the following temporary impacts to inland wetland resource areas are anticipated in the workspace area:

- Approximately 4,500 square feet of impact to Bordering Land Subject to Flooding
- Approximately 12,500 square feet of impact to Riverfront Area

Eversource is continuing to assess these three alternative crossing scenarios to determine the most feasible option which minimizes overall resource area impacts as well as impacts to the parklands located on either side of the crossing.

For the crossing from the Mystic River within the Town of Medford, trenchless technology is proposed to be used (Figure 11). Trenchless technology will result in the least impact to wetland resource areas. Under this scenario, the following temporary impacts to inland wetland resource areas are anticipated in the workspace area:

- Approximately 3,000 square feet of impact to Bordering Land Subject to Flooding
- Approximately 13,500 square feet of impact to Riverfront Area

Under this scenario, the following additional temporary impacts to inland wetland resource areas are anticipated in the pipe makeup area:

- Approximately 500 square feet of impact to Bordering Land Subject to Flooding
- Approximately 4,000 square feet of impact to Riverfront Area

C. Estimate the extent and type of impact that the project will have on wetland resources, and indicate whether the impacts are temporary or permanent:

Note that all measurements presented below reflect the potential maximum impact to each resource area based on the above-described alternatives.

Coastal Wetlands	Area (square feet) or Length (linear feet)	Temporary or Permanent Impact?
Land Under the Ocean	0	N/A
Designated Port Areas	0	N/A
Coastal Beaches	0	N/A
Coastal Dunes	0	N/A
Barrier Beaches	0	N/A
Coastal Banks	0	N/A
Rocky Intertidal Shores	0	N/A
Salt Marshes	0	N/A
Land Under Salt Ponds	0	N/A
Land Containing Shellfish	0	N/A
Fish Runs	0	N/A
Land Subject to Coastal Storm Flowage	0	N/A
Inland Wetlands		
Bank (lf)	60 lf	T
Bordering Vegetated Wetlands	0	N/A
Isolated Vegetated Wetlands	0	N/A
Land under Water	~1,200 sf	T
Isolated Land Subject to Flooding	0	N/A
Bordering Land Subject to Flooding	~4,500 sf	T
Riverfront Area	~17,500 sf	T

D. Is any part of the project:

1. proposed as a **limited project**? ☒Yes ☐No; if yes, what is the area (in sf)?_~33,000 sf Riverfront Area___
2. the construction or alteration of a **dam**? ☐ Yes ☒ No; if yes, describe:
3. fill or structure in a **velocity zone** or **regulatory floodway**? ☐ Yes ☒ No
4. dredging or disposal of dredged material? ☐ Yes ☒ No; if yes, describe the volume of dredged material and the proposed disposal site:
5. a discharge to an **Outstanding Resource Water (ORW)** or an **Area of Critical Environmental Concern (ACEC)**? ☐ Yes ☒ No
6. subject to a wetlands restriction order? ☐ Yes ☒ No; if yes, identify the area (in sf):
7. located in buffer zones? ☒Yes ☐No; if yes, how much (in sf) approximately 35,000 sf

E. Will the project:

1. be subject to a local wetlands ordinance or bylaw? ☒Yes ☐No
2. alter any federally-protected wetlands not regulated under state law? ☐ Yes ☒ No; if yes, what is the area (sf)?

III. Waterways and Tidelands Impacts and Permits

A. Does the project site contain waterways or tidelands (including filled former tidelands) that are subject to the Waterways Act, M.G.L.c.91? _☒Yes ☐No; if yes, is there a current Chapter 91 License or Permit affecting the project site? ☒Yes ☐No; if yes, list the date and license or permit number and provide a copy of the historic map used to determine extent of filled tidelands:

License No. 4687, June 11, 1963 for Mystic River Crossing in Medford
License No. 4702, June 18, 1963 for Aberjona River Crossing in Winchester
License No. 4701, January 24, 1964 for Mystic River Crossing in Boston/Everett

D. Does the project require a new or modified license or permit under M.G.L.c.91? ☐ Yes ☒ No; if yes, how many acres of the project site subject to M.G.L.c.91 will be for non-water-dependent use? Current ___ Change ___ Total ___

** Chapter 91 authorization for non-tidal crossings granted under Final WPA Order of Conditions

If yes, how many square feet of solid fill or pile-supported structures (in sf)? N/A

C. For non-water-dependent use projects, indicate the following:

Area of filled tidelands on the site:____________________
Area of filled tidelands covered by buildings:____________
For portions of site on filled tidelands, list ground floor uses and area of each use:
____
Does the project include new non-water-dependent uses located over flowed tidelands?
Yes ___ No ___
Height of building on filled tidelands________________

Also show the following on a site plan: Mean High Water, Mean Low Water, Water-dependent Use Zone, location of uses within buildings on tidelands, and interior and exterior areas and facilities dedicated for public use, and historic high and historic low water marks.

E. Is the project located on landlocked tidelands? ☒ Yes ☐ No; if yes, describe the project's impact on the public's right to access, use and enjoy jurisdictional tidelands and describe measures the project will implement to avoid, minimize or mitigate any adverse impact: There is potential for landlocked tideland areas within existing roadways and disturbed areas of the proposed project

F. Is the project located in an area where low groundwater levels have been identified by a municipality or by a state or federal agency as a threat to building foundations? ☐ Yes ☒ No; if yes, describe the project's impact on groundwater levels and describe measures the project will implement to avoid, minimize or mitigate any adverse impact:

F. Is the project non-water-dependent **and** located on landlocked tidelands **or** waterways or tidelands subject to the Waterways Act **and** subject to a mandatory EIR? ☐ Yes ☒ No; *(NOTE: If yes, then the project will be subject to Public Benefit Review and Determination.)*

G. Does the project include dredging? ☐ Yes ☒ No; if yes, answer the following questions:

What type of dredging? Improvement ___ Maintenance ___ Both ____
What is the proposed dredge volume, in cubic yards (cys) _________
What is the proposed dredge footprint ____length (ft) ___width (ft)____depth (ft);
Will dredging impact the following resource areas?

Intertidal Yes__ No__; if yes, ___ sq ft
Outstanding Resource Waters Yes__ No__; if yes, ___ sq ft
Other resource area (i.e. shellfish beds, eel grass beds) Yes__ No__; if yes __ sq ft
If yes to any of the above, have you evaluated appropriate and practicable steps

to: 1) avoidance; 2) if avoidance is not possible, minimization; 3) if either avoidance or minimize is not possible, mitigation?

If no to any of the above, what information or documentation was used to support this determination?

Provide a comprehensive analysis of practicable alternatives for improvement dredging in accordance with 314 CMR 9.07(1)(b). Physical and chemical data of the sediment shall be included in the comprehensive analysis.

Sediment Characterization

Existing gradation analysis results? __Yes ___No: if yes, provide results.

Existing chemical results for parameters listed in 314 CMR 9.07(2)(b)6? ___Yes ____No; if yes, provide results.

Do you have sufficient information to evaluate feasibility of the following management options for dredged sediment? If yes, check the appropriate option.

Beach Nourishment ___
Unconfined Ocean Disposal ___
Confined Disposal:
    Confined Aquatic Disposal (CAD) ___
    Confined Disposal Facility (CDF) ___
Landfill Reuse in accordance with COMM-97-001 ___
Shoreline Placement ___
Upland Material Reuse____
In-State landfill disposal____
Out-of-state landfill disposal ____
(NOTE: This information is required for a 401 Water Quality Certification.)

IV. Consistency:

A. Does the project have effects on the coastal resources or uses, and/or is the project located within the Coastal Zone? ☐ Yes ☒ No; if yes, describe these effects and the projects consistency with the policies of the Office of Coastal Zone Management:

B. Is the project located within an area subject to a Municipal Harbor Plan? ☐ Yes ☒ No; if yes, identify the Municipal Harbor Plan and describe the project's consistency with that plan:

WATER SUPPLY SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **water supply** (see 301 CMR 11.03(4))? ☐Yes ☒No; if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **water supply**? ☐Yes ☒No; if yes, specify which permit:

C. If you answered "No" to both questions A and B, proceed to the **Wastewater Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Water Supply Section below.

II. Impacts and Permits

A. Describe, in gallons per day (gpd), the volume and source of water use for existing and proposed activities at the project site:

	Existing	Change	Total
Municipal or regional water supply	________	________	________
Withdrawal from groundwater	________	________	________
Withdrawal from surface water	________	________	________
Interbasin transfer	________	________	________

(NOTE: Interbasin Transfer approval will be required if the basin and community where the proposed water supply source is located is different from the basin and community where the wastewater from the source will be discharged.)

B. If the source is a municipal or regional supply, has the municipality or region indicated that there is adequate capacity in the system to accommodate the project? ___ Yes ___ No

C. If the project involves a new or expanded withdrawal from a groundwater or surface water source, has a pumping test been conducted? ___ Yes ___ No; if yes, attach a map of the drilling sites and a summary of the alternatives considered and the results. ______________

D. What is the currently permitted withdrawal at the proposed water supply source (in gallons per day)? ______Will the project require an increase in that withdrawal? ___Yes ___No; if yes, then how much of an increase (gpd)? ____________________

E. Does the project site currently contain a water supply well, a drinking water treatment facility, water main, or other water supply facility, or will the project involve construction of a new facility? ___ Yes ___No. If yes, describe existing and proposed water supply facilities at the project site:

	Permitted Flow	Existing Avg Daily Flow	Project Flow	Total
Capacity of water supply well(s) (gpd)	_______	________	________	________
Capacity of water treatment plant (gpd)	_______	________	________	________

F. If the project involves a new interbasin transfer of water, which basins are involved, what is the direction of the transfer, and is the interbasin transfer existing or proposed?

G. Does the project involve:

1. new water service by the Massachusetts Water Resources Authority or other agency of the Commonwealth to a municipality or water district? ___ Yes ___ No
2. a Watershed Protection Act variance? ___ Yes ___ No; if yes, how many acres of alteration?
3. a non-bridged stream crossing 1,000 or less feet upstream of a public surface drinking water supply for purpose of forest harvesting activities? ___ Yes ___ No

III. Consistency

Describe the project's consistency with water conservation plans or other plans to enhance water resources, quality, facilities and services:

WASTEWATER SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **wastewater** (see 301 CMR 11.03(5))? ☐Yes ☒No; if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **wastewater**? ☐Yes ☒No; if yes, specify which permit:

C. If you answered "No" to both questions A and B, proceed to the **Transportation -- Traffic Generation Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Wastewater Section below.

II. Impacts and Permits

A. Describe the volume (in gallons per day) and type of disposal of wastewater generation for existing and proposed activities at the project site (calculate according to 310 CMR 15.00 for septic systems or 314 CMR 7.00 for sewer systems):

	Existing	Change	Total
Discharge of sanitary wastewater	________	________	________
Discharge of industrial wastewater	________	________	________
TOTAL	________	________	________

	Existing	Change	Total
Discharge to groundwater	________	________	________
Discharge to outstanding resource water	________	________	________
Discharge to surface water	________	________	________
Discharge to municipal or regional wastewater facility	________	________	________
TOTAL	________	________	________

B. Is the existing collection system at or near its capacity? ___ Yes ___ No; if yes, then describe the measures to be undertaken to accommodate the project's wastewater flows:

C. Is the existing wastewater disposal facility at or near its permitted capacity? ___ Yes___ No; if yes, then describe the measures to be undertaken to accommodate the project's wastewater flows:

D. Does the project site currently contain a wastewater treatment facility, sewer main, or other wastewater disposal facility, or will the project involve construction of a new facility? ___ Yes ___ No; if yes, describe as follows:

	Permitted	Existing Avg Daily Flow	Project Flow	Total
Wastewater treatment plant capacity (in gallons per day)	_______	________	________	________

E. If the project requires an interbasin transfer of wastewater, which basins are involved, what is the direction of the transfer, and is the interbasin transfer existing or new?

(NOTE: Interbasin Transfer approval may be needed if the basin and community where wastewater will be discharged is different from the basin and community where the source of water supply is located.)

F. Does the project involve new sewer service by the Massachusetts Water Resources Authority (MWRA) or other Agency of the Commonwealth to a municipality or sewer district? ___ Yes ___ No

G. Is there an existing facility, or is a new facility proposed at the project site for the storage, treatment, processing, combustion or disposal of sewage sludge, sludge ash, grit, screenings, wastewater reuse (gray water) or other sewage residual materials? ___ Yes ___ No; if yes, what is the capacity (tons per day):

	Existing	Change	Total
Storage	________	________	________
Treatment	________	________	________

Processing	________	________	________
Combustion	________	________	________
Disposal	________	________	________

H. Describe the water conservation measures to be undertaken by the project, and other wastewater mitigation, such as infiltration and inflow removal.

III. Consistency

A. Describe measures that the proponent will take to comply with applicable state, regional, and local plans and policies related to wastewater management:

B. If the project requires a sewer extension permit, is that extension included in a comprehensive wastewater management plan? ___ Yes ___ No; if yes, indicate the EEA number for the plan and whether the project site is within a sewer service area recommended or approved in that plan:

TRANSPORTATION SECTION (TRAFFIC GENERATION)

I. Thresholds / Permit

A. Will the project meet or exceed any review thresholds related to **traffic generation** (see 301 CMR 11.03(6))? ☐Yes ☒No if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **state-controlled roadways**? ☒Yes ☐No; if yes, specify which permit:

MassDOT Highway Access Permit and a Construction and Access Permit and an Article 97 long term easement from the DCR

C. If you answered "No" to both questions A and B, proceed to the **Roadways and Other Transportation Facilities Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Traffic Generation Section below.

II. Traffic Impacts and Permits

A. Describe existing and proposed vehicular traffic generated by activities at the project site:

	Existing	Change	Total
Number of parking spaces	0	0	0
Number of vehicle trips per day	0	0	0
ITE Land Use Code(s):	*		

* The Project primarily consists of installation of underground utilities. Minor modifications at the Woburn and Mystic substations are proposed; however, no change in the post-construction traffic to the substations is anticipated.

B. What is the estimated average daily traffic on roadways serving the site? The project will have temporary impacts related to construction. No change to average daily traffic is proposed.

Roadway	Existing	Change	Total
1.			
2.			
3.			

C. If applicable, describe proposed mitigation measures on state-controlled roadways that the project proponent will implement: The Project will not permanently impact traffic, transit or transportation facilities. Temporary impacts will occur during construction but will be mitigated through implementation of Traffic Management Plans as discussed in Section 4.5 of Attachment A.

D. How will the project implement and/or promote the use of transit, pedestrian and bicycle facilities and services to provide access to and from the project site? N/A – Project is underground infrastructure and will not result in increased traffic.

C. Is there a Transportation Management Association (TMA) that provides transportation demand management (TDM) services in the area of the project site? ☐ Yes ☐ No ; if yes, describe if and how will the project will participate in the TMA: N/A – Project is underground infrastructure and will not result in increased traffic.

D. Will the project use (or occur in the immediate vicinity of) water, rail, or air transportation facilities? ☒ Yes ☐ No; if yes, generally describe: The project will cross the MBTA railroad near Assembly Square Drive in Somerville. The project will also result in work along MBTA bus routes.

E. If the project will penetrate approach airspace of a nearby airport, has the proponent filed a Massachusetts Aeronautics Commission Airspace Review Form (780 CMR 111.7) and a Notice of Proposed Construction or Alteration with the Federal Aviation Administration (FAA) (CFR Title 14 Part 77.13, forms 7460-1 and 7460-2)? N/A

III. Consistency

Describe measures that the proponent will take to comply with municipal, regional, state, and federal plans and policies related to traffic, transit, pedestrian and bicycle transportation facilities and services: The Project will not permanently impact traffic, transit or transportation facilities. Temporary impacts will occur during construction but will be mitigated through implementation of Traffic Management Plans as discussed in Section 4.5 of Attachment A. The installation of the electric transmission line under the MBTA railroad in Somerville will be done through trenchless method to avoid impacts to the railroad.

TRANSPORTATION SECTION (ROADWAYS AND OTHER TRANSPORTATION FACILITIES)

I. Thresholds

A. Will the project meet or exceed any review thresholds related to **roadways or other transportation facilities** (see 301 CMR 11.03(6))? ☐Yes ☒No ; if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **roadways or other transportation facilities**? ☒Yes ☐No; if yes, specify which permit:

MassDOT Highway Crossing Permit; a Construction and Access Permit and an Article 97 long term easement from the DCR; MBTA Access Permit.

C. If you answered "No" to both questions A and B, proceed to the **Energy Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Roadways Section below.

II. Transportation Facility Impacts

A. Describe existing and proposed transportation facilities in the immediate vicinity of the project site: See Section 3.5 of Attachment A for a list of transportation facilities along the Project Route.

B. Will the project involve any

1. Alteration of bank or terrain (in linear feet)? Potential 60 lf
2. Cutting of living public shade trees (number)? No

3. Elimination of stone wall (in linear feet)? No

III. Consistency -- Describe the project's consistency with other federal, state, regional, and local plans and policies related to traffic, transit, pedestrian and bicycle transportation facilities and services, including consistency with the applicable regional transportation plan and the Transportation Improvements Plan (TIP), the State Bicycle Plan, and the State Pedestrian Plan: The Project will not permanently impact traffic, transit or transportation facilities. Temporary impacts will occur during construction but will be mitigated through implementation of Traffic Management Plans as discussed in the Project Description in Attachment A.

ENERGY SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **energy** (see 301 CMR 11.03(7))?
☐ Yes ☒ No; if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **energy**? ☒Yes ☐No; if yes, specify which permit: DPU Approval under MGL c.164 Sec 72 and M.G.L. c. 40A, s. 3

C. If you answered "No" to both questions A and B, proceed to the **Air Quality Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Energy Section below.

II. Impacts and Permits

A. Describe existing and proposed energy generation and transmission facilities at the project site:

	Existing	Change	Total
Capacity of electric generating facility (megawatts)	N/A	N/A	N/A
Length of fuel line (in miles)	N/A	N/A	N/A
Length of transmission lines (in miles)	7.7*	7.7	7.7
Capacity of transmission lines (in kilovolts)	115 kV	0	115 kv

* Work is proposed in existing easements and roadways. Expansion of easements may be required for River crossings at the Aberjona River and the upper Mystic River crossing. The easement expansions will be less than 1 mile in length.

B. If the project involves construction or expansion of an electric generating facility, what are:

1. the facility's current and proposed fuel source(s)? N/A
2. the facility's current and proposed cooling source(s)? N/A

C. If the project involves construction of an electrical transmission line, will it be located on a new, unused, or abandoned right of way? ☐Yes ☒No; if yes, please describe:

D. Describe the project's other impacts on energy facilities and services: The Project will support reliability of the electric grid in the Greater Boston area.

III. Consistency

Describe the project's consistency with state, municipal, regional, and federal plans and policies for enhancing energy facilities and services: The Project purpose is to improve the reliability of electric transmission within the Greater Boston area and address thermal overloads within the existing transmission line. In combination with other planned Greater Boston Area transmission upgrades, the Project provides a system with substantial flexibility to accommodate load growth and potential generator retirements into the foreseeable future.

AIR QUALITY SECTION

I. Thresholds

A. Will the project meet or exceed any review thresholds related to **air quality** (see 301 CMR 11.03(8))? ☐Yes ☒No ; if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **air quality**? ☐Yes ☒No; if yes, specify which permit:

C. If you answered "No" to both questions A and B, proceed to the **Solid and Hazardous Waste Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Air Quality Section below.

II. Impacts and Permits

A. Does the project involve construction or modification of a major stationary source (see 310 CMR 7.00, Appendix A)? ___ Yes ___ No; if yes, describe existing and proposed emissions (in tons per day) of:

	Existing	Change	Total
Particulate matter	________	________	________
Carbon monoxide	________	________	________
Sulfur dioxide	________	________	________
Volatile organic compounds	________	________	________
Oxides of nitrogen	________	________	________
Lead	________	________	________
Any hazardous air pollutant	________	________	________
Carbon dioxide	________	________	________

B. Describe the project's other impacts on air resources and air quality, including noise impacts:

III. Consistency

A. Describe the project's consistency with the State Implementation Plan:

B. Describe measures that the proponent will take to comply with other federal, state, regional, and local plans and policies related to air resources and air quality:

SOLID AND HAZARDOUS WASTE SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **solid or hazardous waste** (see 301 CMR 11.03(9))? ☐Yes ☒No; if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **solid and hazardous waste**? ☐Yes ☒No; if yes, specify which permit:

C. If you answered "No" to both questions A and B, proceed to the **Historical and Archaeological Resources Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Solid and Hazardous Waste Section below.

II. Impacts and Permits

A. Is there any current or proposed facility at the project site for the storage, treatment, processing, combustion or disposal of solid waste? ___ Yes ___ No; if yes, what is the volume (in tons per day) of the capacity:

	Existing	Change	Total
Storage	________	________	________
Treatment, processing	________	________	________
Combustion	________	________	________
Disposal	________	________	________

B. Is there any current or proposed facility at the project site for the storage, recycling, treatment or disposal of hazardous waste? ___ Yes ___ No; if yes, what is the volume (in tons or gallons per day) of the capacity:

	Existing	Change	Total
Storage	________	________	________
Recycling	________	________	________
Treatment	________	________	________
Disposal	________	________	________

C. If the project will generate solid waste (for example, during demolition or construction), describe alternatives considered for re-use, recycling, and disposal:

D. If the project involves demolition, do any buildings to be demolished contain asbestos?
___ Yes ___ No

E. Describe the project's other solid and hazardous waste impacts (including indirect impacts):

III. Consistency

Describe measures that the proponent will take to comply with the State Solid Waste Master Plan:

HISTORICAL AND ARCHAEOLOGICAL RESOURCES SECTION

I. Thresholds / Impacts

A. Have you consulted with the Massachusetts Historical Commission? ☐Yes ☒No; if yes, attach correspondence. For project sites involving lands under water, have you consulted with the Massachusetts Board of Underwater Archaeological Resources? ☐Yes ☒No; if yes, attach correspondence

B. Is any part of the project site a historic structure, or a structure within a historic district, in either case listed in the State Register of Historic Places or the Inventory of Historic and Archaeological Assets of the Commonwealth? ☒ Yes ☐No; if yes, does the project involve the demolition of all or any exterior part of such historic structure? ☐Yes ☒No; if yes, please describe:

C. Is any part of the project site an archaeological site listed in the State Register of Historic Places or the Inventory of Historic and Archaeological Assets of the Commonwealth? ☐Yes ☒No; if yes, does the project involve the destruction of all or any part of such archaeological site? ___ Yes ___ No; if yes, please describe:

D. If you answered "No" to all parts of both questions A, B and C, proceed to the **Attachments and Certifications** Sections. If you answered "Yes" to any part of either question A or question B, fill out the remainder of the Historical and Archaeological Resources Section below.

II. Impacts

Describe and assess the project's impacts, direct and indirect, on listed or inventoried historical and archaeological resources: The Project elements adjacent to historic properties or districts will consist only of in-street installation of the duct bank and cable system. The construction and operation of the Project will not affect any buildings or structures. The Project Description in Attachment A includes additional detail on Historical and Archeological Resources.

III. Consistency

Describe measures that the proponent will take to comply with federal, state, regional, and local plans and policies related to preserving historical and archaeological resources: The Proponent will coordinate with the MHC and the local historical commissions, complete any required pre-construction surveys and review, and comply with any construction-related requirements designed to ensure that there are no adverse effects to historic and archaeological resources from the Project.

CERTIFICATIONS:

1. The Public Notice of Environmental Review has been/will be published in the following newspapers in accordance with 301 CMR 11.15(1):

(Name) Boston Globe North Zone (Date) 5/3
(Name) Medford Transcript (Date) 5/7
(Name) Somerville Journal (Date) 5/7
(Name) Winchester Star (Date) 5/7
(Name) Woburn Advocate (Date) 5/7

2. This form has been circulated to Agencies and Persons in accordance with 301 CMR 11.16(2).

Signatures:

4/29/15	4/30/15
Date Signature of Responsible Officer or Proponent	Date Signature of person preparing NPC (if different from above)
Michael J. Zylich, P.G., LSP	Daniel P. Rukakoski, PWS, CWS, PSS
Name (print or type)	Name (print or type)
Eversource Energy	Tighe & Bond, Inc.
Firm/Agency	Firm/Agency
One NSTAR Way, NE250	53 Southampton Road
Street	Street
Westwood, MA 02090	Westfield, MA 01085
Municipality/State/Zip	Municipality/State/Zip
781-441-3804	413-875-1312
Phone	Phone

Attachment A
Project Description

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Section 1
Project Description

The Mystic to Woburn Transmission Project ("Project") proposed by NSTAR Electric Company d/b/a Eversource Energy ("Company" or "Eversource") involves the installation of approximately 7.7 miles of new electric transmission line between Eversource's existing Woburn Substation in Woburn and Mystic Substation in Everett and modifications at the Woburn and Mystic Substations. Modifications within the substations will be within the existing station fence limits. The Project is located in the municipalities of Woburn, Winchester, Medford, Somerville, Everett, and Charlestown (Boston), Massachusetts. The Project is needed to relieve potential overloads on the existing underground electric transmission Line. The new underground line (the "Project") will operate in parallel with and increase the capacity of the existing electric transmission line. The Project triggers the need for the submittal of an Environmental Notification Form ("ENF") and other Massachusetts Environmental Policy Act ("MEPA") review if required by the Secretary of the Executive Office of Energy and Environmental Affairs under MEPA in accordance with the following thresholds in the Code of Massachusetts Regulations ("CMR"):

- 301 CMR 11.03(1)(b)(3): Conversion of land held for natural resources purposes in accordance with Article 97 of the Amendments to the Constitution of the Commonwealth to any purpose not in accordance with Article 97.

- 301 CMR 11.03(3)(b)1.f.: Alteration of one half or more acres of any other wetlands (Riverfront Area, Bordering Land Subject to Flooding, and potentially Land Under Water).

This narrative provides a description of the proposed Project including existing conditions, project alternatives, project impacts and proposed mitigation measures for review under the MEPA process.

1.1 Proposed Project

The Project involves the installation of a new underground electric transmission line between the existing Woburn Substation and Mystic Substation and parallel to the existing underground electric transmission line (primarily within streets), through the communities of Woburn, Winchester, Medford, Somerville, Charlestown (Boston) and Everett. The Project also involves minor upgrades within the Woburn and Mystic Substations.

The Project will consist of 7.7 miles of new underground electric transmission line to be operated in parallel with the existing underground transmission line. This new line will be a high pressure fluid filled pipe type cable ("HPFF-PTC") system consisting of three stranded and insulated copper cables installed in a sealed 8-inch steel pipe filled with dielectric fluid.

The 8-inch steel pipe, along with two-inch diameter polyvinyl chloride ("PVC") conduits for relay and communication cables, will be installed in a nominal 24-inch wide by 60-inch deep trench. Manholes for pulling in and splicing cables, line testing, and maintenance will be installed at spacing intervals of approximately 2,000 to 2,400 linear feet. Preliminary estimates indicate approximately 17 manholes will need to be installed for the system.

The Project also includes the installation of a new series reactor at Woburn Substation to balance power flows between the existing and new lines and modifications to the line termination connections at Mystic Substation. Construction at the Woburn Substation will include construction of foundations for the series reactor and trenching for HPFF-PTC installation.

1.1.1 Project Route

Figure 1 in Attachment B indicates the "Preferred Route" (the Project) and a "Noticed Alternative Route". The Company, pursuant to M.G.L. c. 164, § 69J and in support of its petition, currently under development, to the Energy Facility Siting Board ("EFSB" or "Siting Board"), conducted a comprehensive alternatives analysis, including a Project Alternatives analysis and a Route Alternatives analysis consistent with the requirements of M.G.L. c. 164, §§ 69H and 69J, to provide a transmission solution that is designed to improve the reliability of the electric system, while minimizing community and environmental impacts and costs. The route alternatives analysis for the Project is summarized in Section 3 of this document. The Project route is primarily located within existing roadways parallel to the existing electric transmission line. The Preferred Route is approximately 7.7 miles long and traverses parallel to the existing underground electric transmission Line and is described below.

Commencing from the Woburn Substation south across an existing electric transmission easement and between existing residences, the proposed route crosses Pond Street in Winchester and continues south on Woodside Avenue to Fletcher Street. Proceeding southwest on Fletcher Street, the route crosses Church Street, which transitions to Bacon Street, and crosses the Aberjona River, through a rotary onto Main Street (Route 38). The route proceeds on Main Street into Medford to another rotary where it heads south on Winthrop Street across the Mystic River and turns east on South Street. At the intersection with Main Street (Route 38), just south of Medford Center, the route transitions to Mystic Avenue in Somerville. Through the rotary, the route traverses south approximately 1,000 feet along Winthrop Street to the Mystic River crossing over Mystic Valley Reservation land – Veterans Memorial Park adjacent to the Winthrop Street Bridge, where it turns on South Street heading east. The Preferred Route proceeds east 1,700 feet to Route 38 and turns south on Route38/Mystic Avenue on the west side of I-93, traversing approximately 9,050 feet in the Medford and Somerville commercial district along Route 38, crosses McGrath Highway (Route 28) and crosses under the elevated portion of I-93 in Somerville. Turning northeast, the Preferred Route crosses under I-93 on Shore Drive and takes an immediate turn south on the east side of I-93 onto the parallel residential street named Bailey Road for 1,800 feet. Continuing further south, the Preferred Route crosses the Route 28/McGrath Highway intersection on the east side of I-93 and proceeds 2,400 feet on Route 38/Mystic Avenue on the east side of I-93 to the Home Depot parking lot where it transitions at an angle off Mystic Avenue through the parking lot for about 550 feet on private property adjacent to the Line 211-514, and then crosses under Assembly Square Drive and the MBTA railroad by trenchless method approximately 500-600 feet to Arlington Avenue where it traversing 1,150 feet. The Route makes a final turn east, traversing approximately 500 feet on and across Alford Street to the existing conduit/tunnel crossing under the Mystic River to the nearby Mystic Substation entry location.

1.1.2 Ancillary Facilities

The Project will require upgrades at Eversource's Woburn and Mystic Substations. The locations of these substations are shown on Figure 1. The installation of a new electric transmission line will require the installation of a new series reactor at Woburn Substation to balance power flows between the existing and new lines, and modifications to the line termination connections at Mystic Substation. The modifications for the Project will not require an expansion of the fence lines at either of these substations. Construction in the Woburn Substation will involve construction of foundations and support structures for the series reactor. The work at both substations will also include trenching for the line installation.

1.2 Project Alternatives

The Company's alternatives analysis included evaluating:

- The "No Action" Alternative
- Transmission Solution Alternatives
- Non-Transmission Alternatives
- Transmission Route Alternatives

These alternatives are described in detail in Section 3 and depicted in Figure 1-A.

Section 2
Existing Conditions and Potential Impacts

2.1 Land Uses

The Project is located within highly urbanized areas of Woburn, Winchester, Medford, Somerville, Boston and Everett. The Project extends between two existing Eversource substations: the Woburn Substation and the Mystic Substation. Exiting the Woburn Substation in the southeast corner, the route parallels the existing electric transmission line within an existing easement that traverses residential properties to connect to the local roadways (Pond Street at Woodside Road). From this point, the route in between the two substations primarily follows existing roadway rights-of-way through urbanized areas, including dense and moderately dense residential areas, mixed commercial areas and transportation corridors, including MBTA rail lines and MassDOT roadways. The Project crosses through a Home Depot parking lot in Somerville. The Project also traverses parkland including Ginn Recreational Park at the Aberjona River Crossing in Winchester, Mystic Valley Parkland and Veterans Memorial Park recreational fields at the upper Mystic River crossing in Medford and Ryan Playground at the lower Mystic River crossing in Boston. Parkland impacts are discussed in more detail below. Figure 2 shows existing land-use conditions.

Land use density was assessed by tallying the total number of residential housing units, commercial, industrial uses, sensitive receptors (i.e. police and fire stations, hospitals, schools, nursing homes, funeral homes, churches, daycares, state and municipal parks and recreation facilities, and elder care facilities) along the candidate routes. Table 2-1 tallies the relative density of the residential housing units, commercial/industrial buildings, sensitive receptors, and open space/recreation areas along the Project route. Since the proposed Project would be installed entirely underground in streets, there are no direct or permanent impacts to land uses along either route. Access to the land uses listed in Table 2-1 would be temporarily effected during construction, and under some circumstances would be affected by noise and dust during trench construction and pipe installation along the Project Route. In summary, the Project Route traverses approximately 4.0 miles of primarily single residence housing, with two apartment buildings located on Winthrop Street near the Route 38/High Street/Winthrop Street Rotary all the way to the junction of South Street and Route 38. The remaining approximate 3.2 miles of the Preferred Route is located in mixed commercial use areas primarily along Route 38/Mystic Avenue.

Table 2-1
Land Use Density Comparison for Preferred Route

Land Use	Preferred Route Noticed Alternative Route
Residential Housing Units	633
Commercial/Industrial Buildings	80
Sensitive Receptors	7
Open Space/Recreation Areas	5

2.2 Historical and Archeological Resources

The Project evaluation of historic resources along the Preferred Route included a search of archival records at the Massachusetts Historic Commission ("MHC") offices to inventory buildings, local historic districts, known archeological sites, and National Register-listed individual buildings and districts. Historic resources that are tourist attractions or recreational uses were also included in the search. Locations that were listed on the federal or state historic registers and archeological record were evaluated as part of the historic resource category. Figure 4 shows the extent of historical and archeological resources.

The Project Route will pass in close proximity to or traverse Inventoried Historic Areas or Local and National Register Historic District boundaries, and a number of Individually Inventoried or listed (state or federal) buildings or structures. The Project Route passes within 500 feet of three known pre-historic archeological sites. There are approximately 64 Individually Inventoried historic properties abutting the Preferred Route. The Project elements in proximity to such Historic and Pre-historic archaeological resources will consist of in-street installation of the pipe and cable system. The in-street construction and operation of the Project will not adversely affect any historic buildings or structures.

In parallel with the MEPA review process, the Company will coordinate with the local historical commissions, and initiate formal consultation with the MHC, complete any subsequent MHC-required pre-construction surveys and review if required, and comply with any warranted construction-related requirements (e.g., Site Avoidance and Protection Plan ("SAPP")) designed to ensure that there are no adverse effects to historic and archaeological resources from the Project.

2.3 Wetlands and Waterways

As previously described and shown on Figure 5, the majority of the new electric transmission line will be installed underground in urban streets, however, the Preferred Route proposes to cross the Mystic River in two locations (in Medford and between Charlestown/Boston and Everett) and the Aberjona River in one location in Winchester. The Company proposes to use an existing spare conduit to route the new line beneath the "lower" Mystic River crossing (between Charlestown/Boston and Everett), thereby avoiding associated impacts with a new crossing of the river.

The installation of the new electric transmission line will involve temporary alterations within areas subject to protection under the Wetlands Protection Act and 310 CMR 10.02, including the Riverfront Area, Bordering Land Subject to Flooding, Bank, Land Under Water and 100-foot buffer zone.

The Project will require two new river crossings as follows:

- the "upper" Mystic River in the Town of Medford, from South Street to Winthrop Street; and
- the Aberjona River in the Town of Winchester, where Bacon Street crosses the River.

Three options are being considered for the Aberjona River crossing in Winchester, to determine a feasible option that minimizes impacts.

1. Trenchless technology (horizontal directional drill or jack and bore) to the south of Bacon Street (Figure 8)
2. Open cut trenching to the south of Bacon Street (Figure 9)
3. Trenchless technology to the north of Bacon Street (Figure 10)

Under Scenario 1, trenchless technology to the south of Bacon Street (Figure 8), the following temporary impacts to inland wetland resource areas are anticipated in the workspace area:

- Approximately 1,600 square feet of impact to Bordering Land Subject to Flooding
- Approximately 17,100 square feet of impact to Riverfront Area

Under Scenario 2, trenching to the south of Bacon Street (Figure 9), the following temporary impacts to inland wetland resource areas are anticipated in the workspace area:

- Approximately 2,500 square feet of impact to Bordering Land Subject to Flooding
- Approximately 10,000 square feet of impact to Riverfront Area
- Approximately 1,200 square feet of impact to Land Under Waterbody
- Approximately 60 linear feet to Bank

Under Scenario 3, trenchless technology to the north of Bacon Street (Figure 10), the following temporary impacts to inland wetland resource areas are anticipated in the workspace area:

- Approximately 4,500 square feet of impact to Bordering Land Subject to Flooding
- Approximately 12,500 square feet of impact to Riverfront Area

Eversource is continuing to assess these three alternative crossing scenarios to determine the most feasible option which minimizes overall resource area impacts as well as impacts to the parklands located on either side of the crossing.

For the crossing from the Mystic River within the Town of Medford, trenchless technology is proposed to be used (Figure 11). Trenchless technology will result in the least impact to wetland resource areas. Under this scenario, the following temporary impacts to inland wetland resource areas are anticipated in the workspace area:

- Approximately 3,000 square feet of impact to Bordering Land Subject to Flooding
- Approximately 13,500 square feet of impact to Riverfront Area

Under this scenario, the following additional temporary impacts to inland wetland resource areas are anticipated in the pipe makeup area:

- Approximately 500 square feet of impact to Bordering Land Subject to Flooding
- Approximately 4,000 square feet of impact to Riverfront Area

The Mystic River and Aberjona River are subject to regulation under Chapter 91 Waterways regulations administered by the MassDEP, and therefore Chapter 91 authorization would need to be installed to allow for construction work. A record review at MassDEP confirmed that there are existing Chapter 91 licenses for the existing electric transmission line under the "upper" and "lower" Mystic River, and Aberjona River issued in 1963 and 1964.

The installation of the new transmission line under the "lower" Mystic River will not result in any impacts since existing conduit will be used, and a Chapter 91 license was obtained for that installation.

A Chapter 91 authorization for the Aberjona River and "upper" Mystic River could be obtained with a Final Order of Conditions issued under the Wetlands Protection Act ("WPA") per the Chapter 91 regulations 310 CMR 9.05(3)(g)3., which allows for "*placement in a non-tidal river or stream subject to jurisdiction under 310 CMR 9.04(1)(e) of fill or structures for which a final Order of Conditions has been issued under M.G.L. c. 131, § 40 and 310 CMR 10.00: Wetlands Protection, and which does not reduce the space available for navigation; such fill or structures are limited to...pipelines, cables, conduits, sewers, and aqueducts entirely embedded in the soil beneath such river or stream.*"

2.4 Rare Species

The Project crosses an area mapped by NHESP as Priority Habitat, PH 1448. The proposed work in this area will be the underground installation of a new electric transmission line parallel to the existing line within an existing easement. The Company will consult with NHESP to discuss any requirements to assess this area and mitigate any potential impact. PH 1448 also abuts both the Preferred Route and Noticed Alternative Route for approximately 670 linear feet along the Winter Pond side of Woodside Road in Winchester. Figure 3 shows the extent of Priority and Estimate Habitats with respect to the Routes. Mitigation measures consist of construction period erosion and sediment controls and limiting work to the existing road extent to avoid impacts to Habitat.

Per 321 CMR 10.14 (6), *construction, repair, replacement or maintenance of ... utility lines,... within existing paved areas and lawfully developed and maintained lawns or landscaped areas, provided there is no expansion of such existing paved, lawn and landscaped areas* is exempt from the requirements of 321 CMR 10.18 through 10.23 and therefore does not require review by the Division of Fisheries and Wildlife.

2.5 Article 97 Lands

The Project route crosses DCR-owned land that is subject to Article 97 of the Amendments to the Constitution of the Commonwealth ("Article 97") at Mystic Valley Parkway and Mystic Lakes at the Aberjona River crossing in Winchester, Mystic Valley Parkland and Veterans Memorial Park recreational fields at the "upper" Mystic River crossing, as well as the City of Boston's Ryan Playground at the "lower" Mystic River crossing. According to Article 97, projects involving the "conversion of land" held or owned by the Commonwealth for natural resource purposes are subject to legislative approval. Along the Project route both sides of the Aberjona River and Mystic River (at the upper crossing) are owned by the Commonwealth of Massachusetts and managed by the DCR. The land associated with Ryan Playground along the lower Mystic River crossing along the Project route is owned by the City of Boston and managed by Boston Parks and Recreation. Eversource has an existing easement on Ryan Playground for underground conduit and cables that cross this property. Eversource is evaluating using this easement for the installation of the new electric transmission line cable. Figure 7 shows Article 97 lands and roadways.

2.6 Public Shade Trees

Massachusetts General Law Chapter 87 defines public shade trees as all trees within a public way or on the boundaries thereof. Based on field reconnaissance the Company does not currently anticipate the need to cut any public shade trees in the public way or along boundaries of the public way to facilitate construction of the Project. Nonetheless, a final assessment will be conducted in consultation with the applicable municipal tree wardens.

2.7 Land Disturbance and Stormwater Runoff

The Project consists of installation of an underground pipe and manhole system primarily within existing roadway rights-of-way, except for the proposed river crossings described in Section 2.3, and railroad crossings. As such, land disturbance will be limited to relatively narrow trenches and soil will be hauled off-site to a managed soil handling site and not be stockpiled over night or during rain events in the streets. Therefore, the potential for land disturbance and soil erosion or sedimentation is minimal. As described in Section 4.4, the Company comply with applicable provisions of the MassDEP Stormwater Management Policy and will implement Best Management Practices ("BMPs") for the control of soil removed and hauled from street work zone, and for control of erosion and sedimentation at work areas near wetland resources and at soil management areas.

2.8 Traffic Congestion and Transportation Resources

Table 2-2 summarizes the percentage of road segment lengths with low, moderate, and high potential traffic congestion for the Preferred and Noticed Alternative Routes. Due to the general location of the Project in a dense urban area, the Project route is located on roads with daily high-volume commuter traffic, including Route 38/Bacon Street/Main Street in Winchester (residential land use), and Route 38/Winthrop Street/Mystic Avenue in Medford and Somerville, which are all commercial districts. Approximately 3.6 miles of the Preferred Route traverse MBTA bus routes. The Project also crosses MBTA railroad in Somerville.

Table 2-2
Lengths of Preferred and Noticed Alternative Route with Low, Moderate, and High Potential for Traffic Congestion

Traffic Congestion Potential Rank	Preferred Route (ln. ft.)/Percent of Entire Length of Route
Low Potential	3,950/ 10%
Moderate Potential	19,900/ 53%
High Potential	12,430/ 33%

The Project will not permanently impact roadways or result in increased traffic on roadways. Construction impacts will be mitigated through traffic management plans, use of trenchless technology under railroad crossings, maintaining two-way traffic as much as possible, and timing work during off-peak times as practicable.

2.9 Noise

This Section evaluates the potential for noise generated during construction to affect noise receptors along the Preferred Route and Noticed Alternative Route.

The potential for noise impacts from construction in public roads is a function of the equipment used and their operating noise levels, the hours of operation, ambient noise levels, and the proximity of sensitive receptors to the construction work zone or activity. Civil construction that may generate temporary noise above ambient levels includes trenching and manhole excavation, ledge removal, and pipe installation, backfilling, cable splicing, and repaving operations.

All of the potential noise impacts associated with the Project will be limited to the localized construction zone area. Noise from construction will have the potential to affect adjacent residences and commercial businesses and pedestrians near the work zone.

Construction associated with the installation of the Project is anticipated to extend through a 20-month period from April 2017 through December 2018, with the potential for final pavement restoration to extend beyond the end of the construction period as it may be scheduled around seasonal restrictions.

Construction and installation of the new electric transmission cable system will follow the same basic construction sequence regardless of the route selected. Consequently, the types and duration of construction-related noise will be similar regardless of the route. The relative impact of construction-related noise along each route will depend in part on the total length of the active work zone and the proximity of residences, commercial businesses and pedestrians along each route.

2.10 Dust Control/Air Quality

Similar to other utility infrastructure in the streets such as water and sewer pipelines, there is the minor potential for fugitive dust and emissions from the trench construction process along the Project Route. As described in detail in section 4.8, the Company will minimize the potential for airborne dust from earth disturbing activities by requiring its contractors to place water trucks with misters in or near the work areas during construction activities. In addition, excavated soils will be directly transferred from the trench to a covered truck to minimize the potential for the release of dust and for soil migration from the work area.

Section 3
Project Alternatives

Pursuant to the ENF requirement to describe the feasible project alternatives, this section describes the alternatives analysis undertaken by the Company to avoid or minimize damage to the environment to the greatest extent feasible. As previously noted, the Company, pursuant to M.G.L. c. 164, § 69J and in support of its petition to the EFSB conducted a comprehensive alternatives analysis, including a Project Alternatives analysis and a Route Alternatives analysis. The Company's alternatives analysis included evaluating:

- The "No Action" Alternative
- Transmission Solution Alternatives
- Non-Transmission Alternatives
- Transmission Route Alternatives

The Company's overriding goal throughout the planning, alternatives analysis, and design phases of the Project has been to select the Project approach alternative that best meets the Project need, with a minimum impact on the environment, at the lowest possible cost.

3.1 No Action Alternative

Conceptually, the Company first assessed a no-action solution. With the No-Action alternative, the Company would not pursue construction or the development of any new transmission facilities nor supply resources such as Demand Side Management ("DSM") measures and new generation sources, but instead would continue to rely upon the existing electric system configuration. The Independent System Operator – New England ("ISO-NE") Working Group and the Company concluded that the overloads on the existing transmission Line cannot be resolved or mitigated by relying on the existing facilities' configuration. Moreover, these overloads cannot be mitigated by interim solutions such as generation re-dispatch or other system operator action. Accordingly, the No-Action Alternative was dismissed from consideration.

3.2 Transmission Solution Alternatives

After a thorough evaluation, ISO-NE selected a comprehensive transmission solution called the "AC Plan" to bolster the region's electric power grid in the Greater Boston Area and ensure continued reliability into the future, including the Project, a new underground electric transmission line between Woburn Substation and Mystic Substation that increases the existing electric transmission line's capacity and thereby increase system reliability.

The proposed Project solution includes parallel connections of new cables with the cables of the existing transmission line to operate as one circuit with higher capacity. This solution requires substation upgrades, all within the existing fence lines of the Woburn and Mystic Substations. The substation upgrades associated with increasing the existing transmission line's capacity include installing a new series reactor at Woburn Substation to balance power flows between the existing and new cables, and swapping the substation termination with the existing termination for the existing transmission line at Mystic

Substation. A summary of the Company's evaluation of Transmission Solution Alternatives follows.

In the course of developing the proposed transmission solution to the existing Line overloads for the AC Plan, the Company considered two basic types of transmission solution alternatives: (1) options to increase the existing Line's capacity so that it does not overload ("Type 1"), and (2) adding new lines, series circuit breakers or autotransformers elsewhere to address the contingencies that can cause existing Line overloads ("type 2").

As part of the Greater Boston Updated Needs Assessment ("Needs Assessment"), the ISO-NE Working Group used load flow analysis to assess the performance of the area transmission system under a series of defined "contingency" situations. The Company recognized early that the sheer volume of new facilities in a Type 2 solution would lead to many distinct projects and a much higher cost as compared to the simpler Type 1 options for increasing the existing Line's capacity. Therefore, a type 2 solution was not further considered.

The Company evaluated Type 1 Transmission Alternatives. Because there are no overhead transmission line right-of-ways or options available between the Woburn and Mystic Substations, the Company initially identified four underground transmission line alternatives that could increase the existing Line's capacity and potentially resolve the existing Line overloads identified Needs Assessment. All four options would increase the capacity of the existing Line between the Woburn Substation and Mystic Substation, but not by equal amounts. In order to resolve the overloads, a Type 1 transmission solution would need to yield a minimum summer long-term emergency ("LTE") rating of the existing Line.

After concluding that two options, an HPFF-PTC cable system, and an XLPE cable system were the best transmission solution alternatives to meet the identified need, the Company further compared these two options. The Company first determined that the environmental and community impacts during construction would be similar for these two options, except that the XLPE option may involve additional impacts associated with more manholes and with a crossing of the lower Mystic River where its cables cannot be placed within an existing spare pipe, as the HPFF-PTC option can. Other considerations for comparing these two transmission solution options are electrical performance, reliability and cost.

Overall, the Company determined that the preferred transmission solution option is to install a new HPFF-PTC system to operate in parallel with the existing Line. The HPFF-PTC system is preferable for this Project because it will require fewer manholes, which is significant with respect to existing dense utility conditions, and HPFF-PTC has a much lower cost for this application; particularly because of the availability of the existing spare pipe beneath the Mystic River.

The proposed solution includes parallel connections of these cables with the cables of the existing Line to operate as one circuit with higher capacity. This solution requires substation upgrades at Woburn and Mystic Substations. The substation upgrades associated with increasing the existing Line capacity include installing a new series reactor at Woburn Substation to balance power flows between the existing and new cables, and swapping the substation termination with the existing termination for the existing Line at Mystic Substation and the existing line pressurization equipment.

3.3 Non-Transmission Solution Alternatives

The Company engaged London Economics International ("LEI") to assess the feasibility and cost of non-transmission alternatives ("NTA") to the Mystic to Woburn Transmission Project. As input to the LEI Report, the Company identified the specific size of resources and their specific locations within the transmission system that would be needed to mitigate contingency transmission overloads absent construction of the new Line.

Also as input to the non-transmission study, the Company also conducted dispatch optimization analyses to determine the resources needed to address thermal overloads in the Greater Boston study area if construction of the new Line were to be deferred.[1] This assessment considered the reliability needs for the projected 2023 transmission system serving the Greater Boston study area under contingency conditions. The analysis identified the specific size of resources and their specific locations within the transmission system that would be needed to mitigate transmission overloads seen on the 2023 transmission system absent construction of the new Line.

Using this information, LEI began by identifying a broad range of possible NTA technologies for consideration, including several types of generation sources, utility-scale solar with and without storage, distributed-scale solar with and without storage, battery storage, active demand response, and passive demand response (e.g. energy efficiency).

LEI assessed the ability of various non-transmission technologies to address contingency conditions at each location. LEI also identified the gross and net levelized cost of entry ("LCOE") for each technically feasible technology, and used this information to calculate the annual cost to ratepayers of deferring construction of the new line using these technologies. LEI determined that the total net direct cost of the least cost technically feasible NTA solution would be significantly higher than the proposed underground transmission Line project. The higher cost to customers of the non-transmission alternative to the transmission Line, combined with the physical and logistical difficulties of implementing such a solution in a timely and lasting fashion, makes an NTA a substantially less desirable solution to the identified need. Overall, the Mystic to Woburn Transmission Project better meets the goal of providing a robust, secure and reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

3.4 Transmission Route Alternatives

Following an analysis of a variety of potential project alternatives, as described in Section 3.2, the Company determined that the preferred solution to meet the identified Project need at the lowest reasonable cost and meet reliability standards is to install a new underground HPFF-PTC transmission line between the existing Woburn Substation and the Mystic Substation. This section describes the process the Company conducted to select a Preferred Route and a Noticed Alternative Route for the proposed new underground transmission line.

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[1] The modeling assumed that all other elements of the AC Solution Plan are built.

The Company together with its engineering and environmental consultants, developed and implemented a comprehensive analytical process to identify a reasonable variety of potential candidate transmission routes for screening and analysis in order to ensure that a superior route was not overlooked and that the optimal route was selected consistent with the EFSB's standards and applicable precedents, as well as MEPA environmental standards and thresholds.

The route selection process was initiated by defining a geographic "study area" for potential route corridors and developing objective initial route corridor guidelines and candidate alternative route evaluation criteria for later ranking and scoring. The Company, while looking for "geographic diversity", initially identified the Route Study Area using United States Geological Survey (USGS) maps, Massachusetts Geographic Information System (MassGIS) data, aerial photography, and field reconnaissance to identify existing linear corridors that would support routing of a new circuit between the Woburn and Mystic substations.

The focus of this initial mapping exercise was to find existing infrastructure corridors for a potential transmission line route that are located adjacent to or within existing ROWs or corridors, including roadways, railroads, electric transmission lines, and natural gas pipelines. These existing corridors are typically relatively direct, have few turns, avoid private property, and were found to generally minimize the overall length of the proposed line between the Woburn and Mystic Substations. This initial mapping was also used to identify potential resource areas important to the evaluation process such as parks, conservation land or reservations; water supply reservoirs; and, wetland and river crossings.

As stated, existing routing opportunities identified in the Project study area include existing transmission ROWs, active and abandoned rail beds, and road and highway ROWs. Use of private lands, undeveloped "greenfield" parcels, and lands in active recreations or open space use were observed and documented, but not considered as practical routing opportunities.

Using mapping and field verification, the Company eliminated two of the four preliminary route corridors from further consideration and evaluation because they were considerably longer and had identified constraints that would otherwise not provide opportunities to minimize environmental and community effects when compared to the other two initial route corridors.

The Company then identified six alternative candidate routes and proceeded to evaluate these candidate routes (see Figure 1). Each of the six candidate routes was scored and ranked based on eighteen built, natural resource, and design/construction criteria.

A scoring and weighting system was developed to allow for unweighted and weighted ranking of the candidate routes with respect to each other. The Company used these scores, together with conceptual cost estimates and a reliability assessment of each candidate route, to select a Preferred Route and a geographically-distinct Noticed Alternative Route (see Figure 1-A).

The Company has therefore determined that the Preferred Route is overall the best of the candidate routes in terms of the balance of built and natural resource environment, design/construction feasibility, and overall costs. The Preferred Route represents the shortest and most direct route, and it avoids, to the extent possible, major traffic congestion complications and disruptions in municipal centers with a high concentration of commercial or residential units. The Preferred Route also has the fewest road segments with narrow street widths and utility-dense roadways. The Company also selected a feasible alternative or "Noticed Alternative". The Preferred and Noticed Alternative Routes are further described and a summary of a comparison are provided as follows.

Both routes are depicted on the figures in Attachment B.

3.4.1 The Selection of the Preferred and Noticed Alternative Routes

Preferred Route

The **Preferred Route** for the new Mystic to Woburn Transmission Project is approximately 7.7 miles long and traverses parallel to the existing underground electric transmission line, heading from the Woburn Substation from the southeast corner through an existing easement to the Pond Street/Woodside Road intersection in Winchester. The route then follows existing roads through Winchester, Medford, Somerville, and Charlestown (Boston), terminating at the Mystic Substation in Everett. This route requires two river crossing: the Aberjona River in Winchester and the Mystic River in Medford (the "upper" Mystic River crossing). The new transmission line will be installed in existing conduit under the Mystic River between Charlestown (Boston) and Everett (the "lower" Mystic River crossing), and will exit the conduit in an existing manhole in the Mystic Substation.

Noticed Alternative Route

The **Noticed Alternative Route** is approximately 9.2 miles and proceeds from the southeastern corner of the Woburn Substation parallel to the existing underground transmission line through an existing easement to the Pond Street/Woodside Road intersection in Winchester. The route then follows existing roads through Winchester, Medford and Everett. This route includes one river crossing at the Malden River, between Medford and Everett.

Ancillary Facilities

The Project will require changes at the Company's Woburn and Mystic Substations. Regardless of the route selected, the installation of a new electric transmission line will require a new series reactor at Woburn Substation to balance power flows between the existing and new lines and swapping the existing termination for the existing transmission line at Mystic Substation. The modifications for this Project will not require an expansion of the fence lines at either substation site, and will not require a zoning exemption in the Town of Woburn, or any environmental resource permits. Therefore, ancillary facilities associated with the Project do not materially affect the choice between the Preferred Route and the Noticed Alternative Route.

3.4.2 Preferred Route and Noticed Alternative Route Comparison Conclusion

The built and environmental resource comparison between the Preferred Route and Noticed Alternative Route for the Mystic to Woburn Transmission Project revealed the following differences.

1. The Preferred Route is approximately 1.5 miles shorter than the Noticed Alternative Route.
2. The Preferred Route abuts 471 fewer residential units, 88 fewer commercial/industrial buildings, eleven fewer sensitive receptors, and has one additional recreational area than the Noticed Alternative Route.

3. Based on its shorter length and fewer linear feet of high potential traffic congestion roadways and roadways with MBTA bus service, the Company determined that the Preferred Route has the lower potential for construction-related traffic impacts, which will result in fewer construction costs, and less potential to adversely affect the construction schedule.
4. Overall, because the Preferred Route is shorter and has significantly less residential, commercial and industrial buildings, work along the Preferred Route has the potential to result in less construction noise impacts overall, and for a significantly fewer number of residences, commercial and industrial buildings, and sensitive receptors.
5. The Preferred Route does not traverse in the vicinity of active MCP sites, while the Noticed Alternative Route traverses in the vicinity of seven. The Company has concluded that the Preferred Route has significantly less potential to encounter contaminated soil during construction.
6. Construction of the New Line would entail the same primary construction activities and sequence regardless of the route selected. Generally dust and emissions from equipment can be sufficiently mitigated with appropriate BMPs and emissions controls. However, because the Preferred Route is approximately 1.5 miles shorter than the Noticed Alternative Route, the potential for adverse effects from dust and equipment emissions would be less along the Preferred Route as there are a lesser number of residences, businesses and sensitive receptors along this route.
7. The Preferred Route passes fewer total individual historic places or buildings. Neither route passes individual structures that are open to visitation by the public. The Preferred Route passes fewer historic places (i.e. 64 vs. 71) than the Noticed Alternative Route, however, since the Project will have little potential to adversely impact these individual properties during construction, the Company determined that there is no meaningful difference between the Preferred Route and Noticed Alternative Route with respect to their potential to impact historic properties or buildings.
8. While the proposed trenchless methods for river crossings would avoid direct impacts to river and wetland resources, the river crossings for the both the Preferred Route and Noticed Alternative Route are subject to filing a NOI application under the WPA regulations administered by the Winchester and Medford Conservation Commissions, and other associated resource permits (i.e. local wetland by-laws/ordinances, Chapter 91 Waterways and ACOE Section 10). The Company determined that there is no meaningful difference between the Preferred Route and Noticed Alternative Route in terms of wetland resource filing requirements.
9. Both the Preferred Route and Noticed Alternative Route involve routing and potential easement acquisitions within Article 97 jurisdiction. The Company has determined that these permitting implications are comparably similar and does not appreciably affect the determination of the selection of the Preferred and Noticed Alternative.

Table 3-1 summarizes the environmental comparison results for the Preferred and Noticed Alternative Routes. Primarily because of its greater length, the Noticed Alternative Route has greater potential for disruption and construction impacts associated with the built environment, including more potential disruption of individual residences, commercial businesses, and sensitive receptors; more potential to adversely affect traffic congestion; more potential to elevate noise and dust levels near residences, commercial businesses, sensitive receptors and environmental resources. On the basis of this analysis, the Company has concluded that the Preferred Route is superior to the Noticed Alternative Route with respect to built and environmental resource impact criteria and there is no material difference between the routes in terms of reliability. A +/=/- rating is used to summarize the results and compare the routes, with a + symbol indicating that the route would have the lesser amount of impact for that particular criterion. Therefore, the Preferred Route for the new Mystic to Woburn Transmission Project will best meet the identified need at the lowest reasonable cost and with the least environmental impact.

Table 3-1
Comparison of Preferred Route and Noticed Alternative Route Effects

Built and Environmental Resource Impact Criteria	Preferred Route	Noticed Alternative Route
Land Use	+	-
Traffic Congestion	+	-
Noise	+	-
Contaminated Soil (Oil and Hazardous Materials)	+	-
Dust/Air Quality	+	-
Historic/Archaeological Resources	=	=
Wetlands/Waterways/Article 97 Filings	=	=
Land Disturbance/Erosion Control	+	-

+ indicates less potential for impact
= indicates no difference between routes
- indicates more potential for impact

Section 4
Mitigation Measures

This Section summarizes the mitigation, compliance and monitoring measures the Company proposes to implement in order to minimize impacts during construction of the proposed Project.

Potential impacts to the built environment and natural resource environment resulting from the construction process will be temporary in nature and will be mitigated. Construction mitigation measures include traffic management, construction noise control, stormwater runoff and sediment migration control, dust control to protect air quality, protection of public shade trees, and the appropriate management of excavated soils. These measures are discussed in greater detail in the following sections.

At various points in the trenching and construction process, it will be necessary to excavate open trenches that may temporarily impede access to residences, businesses, and parking. During the trenching and pipe installation procedures, the Company and the construction contractor will make every reasonable effort to notify affected residences and businesses prior to construction in their area, and take measures to maintain access such as using steel plates over open trenches when not working directly on the pipe installation process. At the end of each work day, any remaining open trenches will be covered with securely-anchored steel plates to withstand traffic loading.

4.1 Land Use Mitigation

Land use and facility access impacts associated with the Project will be temporary in nature and confined to the area of construction work zone that ranges from 100 to 400 linear feet and associated work time. On average, under normal trenching conditions, the duration of construction activity associated with pipe installation at any one location is about seven days. In some locations, evening construction may be more appropriate. Work hours along the construction route will be restricted, to the extent possible, to the most appropriate work hours when progressing through areas with sensitive receptors such as hospitals, schools, and playgrounds. The Company will coordinate closely with municipal officials, including Police, Fire and School Department officials, and Recreation and Park Managers to identify land and facility use timeframes and concerns, develop work schedules that minimize access constraints, and implement appropriate mitigation measures to minimize disruption during construction.

4.2 Historical and Archeological Resource Mitigation

As previously noted, the Project will involve trench and manhole excavation in urban streets through inventoried historic districts with a number of Individually Inventoried or listed (state or federal) buildings or structures. Trench and manhole excavations in the streets will not likely affect abutting buildings or structures. Notwithstanding the unlikelihood of impacts to historic places from this activity, Eversource will undergo the MHC review process for historic resources as described below.

Historic archaeological resources or places could be affected during construction by potentially disturbing undiscovered archeological resources during trench excavation, or disrupting access to historic places, and/or generating noise and dust that can be a temporary nuisance to residents or patrons of historic places.

The Company will coordinate with the MHC and the local historical commissions, complete any required pre-construction surveys and review, and comply with any construction-related requirements designed to ensure that there are no adverse effects to historic and archaeological resources from the Project.

4.3 Wetlands/ Waterways Mitigation

Most work will occur within the limits of existing roadways and disturbed areas. A total of three waterway crossings are proposed (one existing and two proposed): the Aberjona River in Winchester, the upper Mystic River in Medford and the lower Mystic River between Charlestown (Boston) and Everett. The lower Mystic River crossing will use existing conduit to avoid impacts to the river. The upper Mystic River crossing is proposed to use trenchless technology to avoid work within the waterway. The construction set-up for the trenchless method will involve temporary alterations within the regulated resources defined in the Massachusetts WPA and 310 CMR 10.02, including Riverfront Area. Eversource is conducting a comprehensive alternatives analysis of trench and trenchless design/construction options and opportunities to minimize wetland resource area impacts at the Aberjona River crossing. Potential impacts to Riverfront Area, Bordering Land Subject to Flooding, Bank and Land Under Water are anticipated. The Project will comply with the applicable provisions and mitigation requirements under the Wetland Protection Act regulations 310 CMR 10.00 et seq, Chapter 91 Waterways regulations 310 CMR 9.00, and Water Quality Certification regulations 314 CMR 9.00.

The Project will require a NOI application filing under the WPA regulations administered by the Winchester and Medford Conservation Commissions, the Town of Winchester Chapter 13 – Wetlands By-laws, the City of Medford Chapter 87 – Wetlands Ordinance, and Chapter 91 authorization under the Public Waterfront Act. In addition, the Project crosses the natural causeway of Winter Pond in Winchester on Woodside Avenue. In its local and state applications, the Company will identify work procedures and indicate on project drawings the location of and installation procedures where erosion and sedimentation control barriers and dewatering basins, if necessary, will be installed, and a description of soil and vegetation restoration procedures following construction.

4.4 Land Disturbance/Erosion Control Mitigation

During excavation activities associated with the Project, the Company will implement appropriate BMPs for the control of erosion and sedimentation in active work zones. Regular inspections will be undertaken by the Environmental Inspector to ensure that erosion and sediment control procedures and features are implemented and maintained. In any location of the street work zone where stormwater runoff discharges to a local storm drain or catch basin in an active construction zone or trench area catch basin inlet protection will be installed prior to construction. Catch basin inlet protection procedures will be site-specific, but may consist of one or a combination of techniques, including the use of geotextile filter fabric "socks", filter bags, and straw or fiber rolls/blocks or bales, as appropriate, to filter or intercept sediment prior to discharging to the collection system. When the disturbed excavation area is stabilized with temporary or permanent patch or pavement, catch basin inlet protection will be removed and any accumulated sediment properly disposed.

Excavated soil will be loaded directly into trucks and transported to an off-site soil stockpile area or shipping directly to the applicable disposal facility. This will minimize the potential for soils to migrate into the municipal storm drain system. Excess soil will be tested and disposed of properly.

The temporary disturbance of the work zone will be confined to the 2-4 foot wide trench area. Most phases of construction will result in very limited exposed soil, and disturbed soils will be covered at the end of each work day until the trench is backfilled with flowable fill and a temporary patch of sidewalk or street is applied.

Control measures will be maintained in place from the commencement of construction activity until final site stabilization is achieved. The road surface in the vicinity of the active construction zone will be maintained and swept to ensure that any spilled soils are promptly removed from the road surface to limit the potential for off-site transport or tracking.

Best management practices will be implemented to minimize the volume of stormwater runoff from adjacent areas from entering the excavation areas or trench. This will minimize trench dewatering requirements and facilitate soil management activities. Structural controls will be used to divert stormwater runoff flows away from disturbed areas, or otherwise limit the discharge of sediment from exposed areas.

Following extended rainfall events, if storm water is not sufficiently prevented from discharging to open trench, trench dewatering may be necessary. If water is encountered in the trench, the preferred method for the management of dewatering effluent will be to return the dewatering effluent back to another section of open trench. If necessary, dewatering pumps, or fractionation tanks and associated appurtenances necessary will be implemented for the removal of groundwater from the excavation and temporary storage of this water. If disposal is required, local, state and federal requirements will be followed. If trench dewatering becomes necessary following a rain event or for relatively small volumes of ground water, trench water will be pumped from the trench using a temporary gravel sump or elevated off of the trench bottom to avoid unnecessary removal of sediments. To facilitate this, sections of the trench not in the immediate work area for pipe installation may be segregated using an earthen berm, sandbags or other suitable material, such as flowable fill, to provide a contained location for the pumped water.

4.5 Traffic Mitigation

Traffic impacts associated with the Project will be temporary in nature and confined to the area of construction work zone that ranges from 100 to 400 linear feet and associated work time. The Company will coordinate closely with municipal Departments of Public Works and Traffic Departments to develop appropriate Traffic Management Plans ("TMPs"), and will implement a variety of mitigation measures to minimize traffic disruption, inconvenience to drivers, and parking and bus service patrons during construction. A summary of the municipal coordination and the development of TMPs that the Company is committed to undertaking is provided below.

Open trenching and pipe installation will necessitate lane restrictions and some closures on narrow or constrained streets. The Company will conduct pre-construction municipal outreach meetings with appropriate municipal representatives and representatives of the affected businesses in commercial areas. The Company is aware of the potential traffic impacts during construction. Every effort will be made to carefully coordinate the construction activities, schedule, and the development of TMPs to minimize impacts on businesses and others relying on these transportation corridors. Prior to commencing construction, the Company will consider and incorporate the following elements into the street-specific TMPs.

- Develop ongoing coordination with police and fire departments;
- Provide provisions for emergency vehicle access;
- Establish appropriate lane location adjustments and ensure safe travel widths within the work zone to maintain safe traffic passage and flow with appropriate roadway level of service and minimize effects due to short-term lane closure(s);
- Organize work schedules and construction duration of proposed lane closures, road closures, and/or detours where necessary;
- Install appropriate traffic-control devices such as barricades, reflective barriers, advance warning signs, traffic regulation signs, traffic control drums, flashers, detour signs, and other protective devices as approved by the various municipalities and MassDOT;
- Identify locations where temporary provisions may be made to maintain access to homes and businesses;
- Establish sufficient routing and safeguarding of pedestrian and bicycle traffic;
- Maintain continuity of MBTA, school bus, and private motor coach routes;
- Communicate with adjacent businesses to avoid interruptions to critical product deliveries; and,
- Develop a system to notify municipal officials, local businesses, and the public of the timing and duration of closed curbside parking spaces and travel restrictions.

The TMPs will be developed with input from the municipalities and business groups, and submitted for review and approval by appropriate municipal authorities prior to construction. Traffic control plans will be developed consistent with the Federal Highway Administration's *Manual on Uniform Traffic Control Devices for Streets and Highways* and MassDOT's publication, *Work Zone Safety*.

4.6 Noise Mitigation

All construction activities will be temporary in nature. Construction will occur during typical work hours (Monday through Friday, 7:00 A.M. to 5:00 P.M. and Saturday from 9 A.M. to 5 P.M.). In general, the construction crews involved in trench excavation and pipe installation are expected to progress at an average rate of approximately 100-200 feet per day. On average, under normal trenching conditions, the duration of construction activity associated with installation at any one location is about seven days. In some locations, such as those completely within commercial and industrial properties, evening construction may be more appropriate. Work hours along the construction route will be restricted, to the extent possible, to the most appropriate work hours when progressing through areas with sensitive receptors such as hospitals, schools, and playgrounds.

Construction operations such as cable splicing and oil-filling utilize mechanical equipment. Splicing high-voltage transmission cable is a time-consuming, complex operation. The splicing activities will be continuous, typically taking place over four or five extended work days at each manhole location. The splicing operation requires a splicing van and a generator. The splicing van contains all of the equipment and material to make a complete splice. At times, an air conditioning unit will be used to control the moisture content in the manhole. A portable generator will provide the electrical power for the splicing van and air conditioning unit. The generator will be muffled to minimize noise. Construction activities will comply with municipal noise ordinances and bylaws.

In addition, the Company will implement the following procedures during construction to mitigate elevated noise levels:

- Require the use of well-maintained equipment with functioning mufflers as applicable;
- Require strict compliance with MassDEP's Anti-Equipment Idling regulations to prevent equipment from idling and producing unnecessary noise while not in productive use; and
- Provide construction contractors with training that highlights the Company's requirements with respect to well-maintained equipment, anti-idling and other relevant policies.

4.7 Construction Soils Management

Encountering contaminated soils during trench operations can slow excavation pace due to special soil handling procedures, and increase costs for soil disposal. The Company will implement pre-construction soil characterization testing to determine site specific potential of encountering soil contamination and develop a Soil and Groundwater Management Plan to provide its construction contractor(s) with information regarding soil and groundwater management requirements during construction of the Project. This plan will provide guidelines for the management of regulated and non-regulated materials for the protection of human health, safety, public welfare, and the environment. A Licensed Site Professional ("LSP") will coordinate soil management activities during construction to ensure compliance with the MCP.

Excavated soil will be managed in accordance with 310 CMR 40.0030 of the MCP (Management Procedures for Remediation Waste) pending off-site recycling/disposal. Soil excavated from along public roadways that is not reused as backfill will be loaded into trucks and transported off-site using a Material Shipping Record ("MSR"). Soil transported off-site may be taken to a designated staging area for temporary storage or transported directly to the recycling/disposal facility.

Following daily construction activities, soil stockpiles at the staging area(s), if any, will be covered with a minimum of 6-mil polyethylene sheeting as needed. Equipment and vehicles that leave the work area will be inspected and broom-cleaned or decontaminated to ensure that soils are not tracked off-site. In the event that wet soils are to be transported off-site, appropriate measures shall be taken to ensure that no liquids are spilled from the trucks onto roadways (e.g., truck liners).

4.8 Dust Control and Air Quality Mitigation

To minimize the potential for airborne dust from earth disturbing activities, the Company will work with its contractors to place water trucks with misters in or near the work areas during construction activities as necessary. In addition, excavated soils will be directly transferred from the trench to a covered truck to minimize the potential for the release of dust and for soil migration from the work area.

To minimize air emissions for equipment operation, the Company will direct its contractors to retrofit any diesel-powered, non-road construction equipment rated 50 horsepower or above, whose engine is not certified to US EPA Tier 4 standards and that will be used for 30 days or more over the course of the Project, with US EPA-verified (or equivalent) emission control devices (e.g., oxidation catalysts or other comparable technologies).

The Company exclusively uses ultra-low-sulfur diesel ("ULSD") fuel in its own diesel powered construction equipment and will require its contractors to do the same for this Project. ULSD has a maximum sulfur content of 15 parts per million compared to 500 parts per million for low-sulfur diesel fuel (a 97 percent reduction).

The Company and its contractors will comply with state law (G.L. c. 90, § l6A) and MassDEP regulations (310 CMR 7. 11 (1)(b)), which limit vehicle idling to no more than five minutes except for vehicles being serviced, vehicles making deliveries that need to keep their engines running, and vehicles that need to run their engines to operate accessories.

4.9 Management of Fuels, Waste Oil, and Hazardous Wastes

The Contractor will be required to conduct the work in an environmentally safe manner and in accordance with applicable regulations for the management of fuels, waste oils, and hazardous substances. Any hazardous materials will be transported, stored, and handled as recommended by the suppliers and/or manufacturers, and in compliance with applicable federal or state regulations.

The contractor will have available at all locations where work is taking place a spill kit.

4.10 Shade Tree Mitigation

Based on field reconnaissance the Company does not currently anticipate the need to cut any public shade trees in the public way or along boundaries of the public way to facilitate construction of the Project. Nonetheless, a final assessment will be conducted in consultation with the applicable municipal tree wardens. In most instances, public shade trees are located interior to the curb line and far enough removed from the likely cable trench location that they would not be adversely affected either by construction or by the long-term existence of the transmission cable. Street-tree root systems are typically confined to the close proximity of the tree base and do not commonly extend beyond the curb line and under paved streets because of high soil compaction, little interstitial space, and the general lack of sufficient oxygen, soil, water, and nutrients. Essentially, tree roots will grow where there is space, and will therefore grow on the unimpeded edges of sidewalks and away from the street edge.

The Company will implement the following practices to protect public shade trees that could be impacted along the Mystic to Woburn Transmission Project:

- Erect and maintain a temporary fence around the perimeter of individual tree pits (the area between the curb and sidewalk where the tree resides) until construction in that area is complete.
- If excavation for new construction is required within the tree pit area and sidewalk, the Tree Warden will be contacted before any work begins.
- Trees and vegetation will be repaired or replaced in a manner approved by the Tree Warden at the Company's expense.

4.11 Community Relations Plan

The Company will develop a detailed Community Relations Plan for municipal coordination and community outreach during construction, including notification to residences and businesses 48 hours prior to street opening on their street, "No Parking" notification and instructions.

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Attachment B
Figures

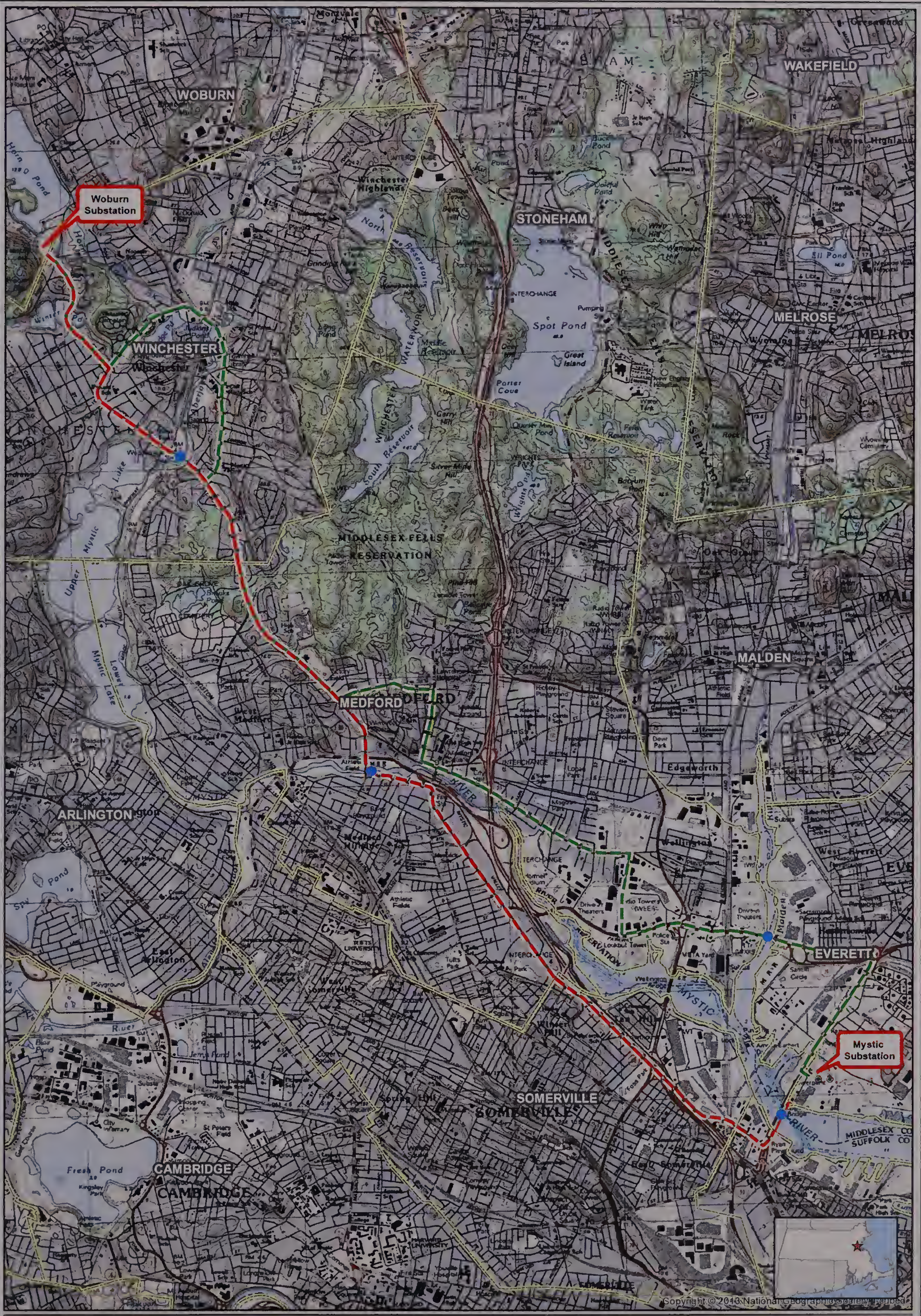
WOBURN
WAKEFIELD
Woburn Substation
STONEHAM
Spot Pond
MELROSE
WINCHESTER
MIDDLESEX FELLS RESERVATION
MALDEN
MEDFORD
ARLINGTON
EVERETT
Mystic Substation
SOMERVILLE
CAMBRIDGE
Fresh Pond
MIDDLESEX CO
SUFFOLK CO
Copyright:© 2013 National Geographic Society, i-cubed
Legend
Preferred Route
Noticed Alternative Route
Existing Mystic River Crossing
Waterbody Crossing
Municipal Boundary
1 in = 2,750 ft
0 1,000 2,000
Feet
N

FIGURE 1 PROJECT LOCATION

Mystic to Woburn
Transmission Project
Preferred Route and
Noticed Alternative

April 2015

Tighe&Bond

POWER Environmental Services Div

Basemap: This map presents land cover imagery for the world and detailed topographic maps for the United States. Copyright: © 2013 National Geographic Society, i-cubed

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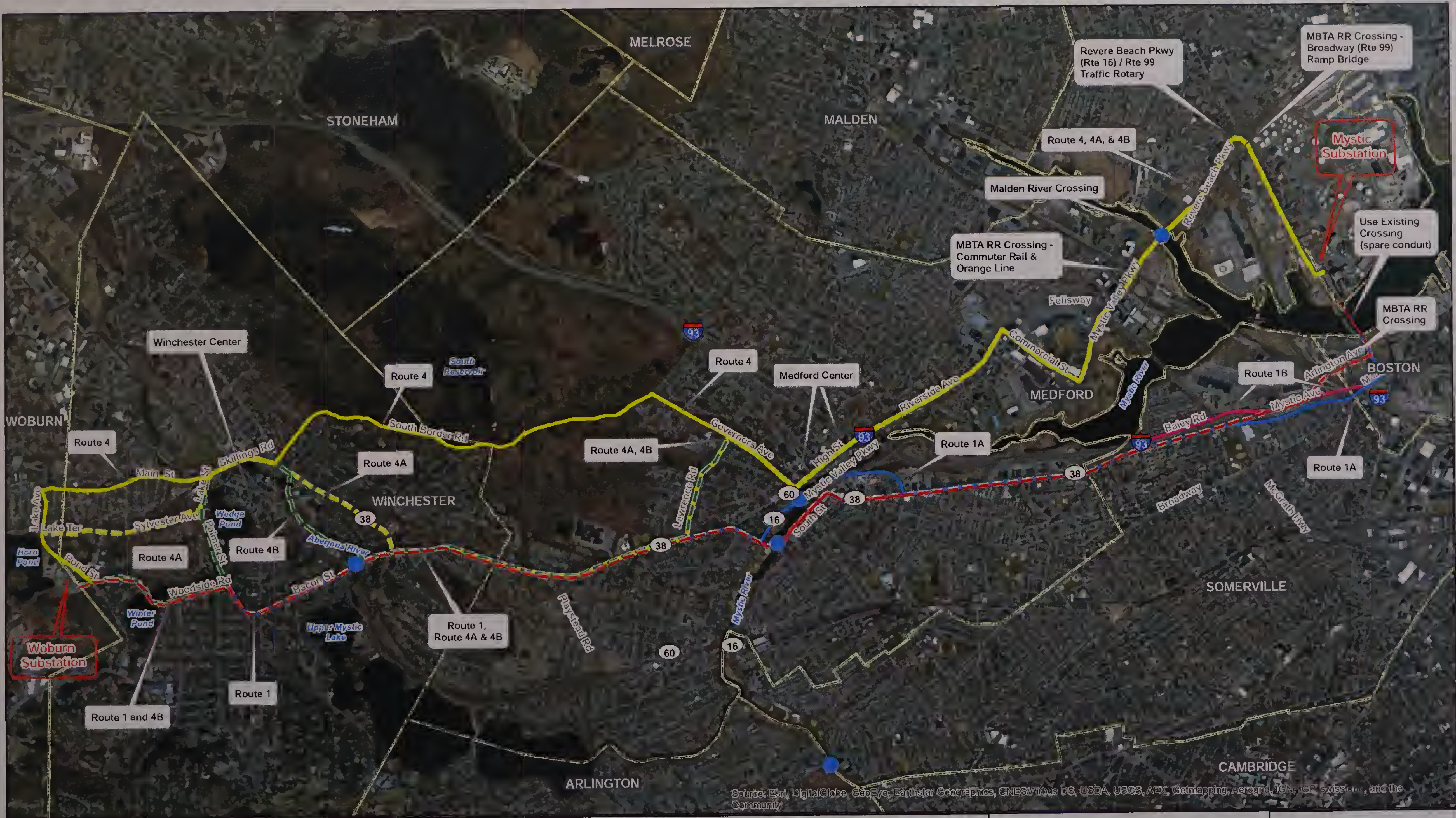
MELROSE
STONEHAM
MALDEN
WOBURN
WINCHESTER
MEDFORD
BOSTON
SOMERVILLE
CAMBRIDGE
ARLINGTON
MBTA RR Crossing - Broadway (Rte 99) Ramp Bridge
Revere Beach Pkwy (Rte 16) / Rte 99 Traffic Rotary
Mystic Substation
Route 4, 4A, & 4B
Malden River Crossing
Use Existing Crossing (spare conduit)
MBTA RR Crossing - Commuter Rail & Orange Line
MBTA RR Crossing
Fellsway
Revere Beach Pkwy
Mystic Valley Pkwy
Commercial St
Route 1B
Arlington Ave
Mystic Ave
Route 1A
Mystic River
Riverside Ave
Baley Rd
Route 1A
Route 1A
McGrath Hwy
Broadway
Winchester Center
Route 4
South Reservoir
Route 4
Medford Center
Route 4
South Border Rd
Route 4A
Route 4A, 4B
Governors Ave
High St
Mystic Valley Pkwy
Skillings Rd
Main St
Lake St
Lake Ave
Lake Ter
Sylvester Ave
Wedge Pond
Palmer St
Route 4B
Route 4A
Aberjona River
Horn Pond
Pond St
Woodside Rd
Winter Pond
Bacon St
Upper Mystic Lake
Lawrence Rd
Playstead Rd
South St
Mystic River
Route 1, Route 4A & 4B
Route 1
Route 1 and 4B
Woburn Substation
93
38
60
16

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the Community

INDEX MAP

Legend

- 🟥 🟥 Route 1 (Parallel Lines 211/514)
- ― Route 1A (MBTA RR crossing, use Maffa Way Bridge & Rte 38 south ramp)
- ― Route 1B (MBTA RR Crossing; use Rte 38 (Main Street/Mystic Avenue) Bridge)
- ― Route 4
- 🟨 🟨 Route 4A
- 🟩 🟩 Route 4B
- ― Existing Mystic River Crossing
- ☐ Municipal Boundary
- ● Waterbody Crossing

Map Notes.
Basemap. 2011-2013 Orthophotographs. MassGIS

0 1,000 2,000 4,000
Feet

Mystic to Woburn
Transmission Project

Figure 1-A

Preferred Route &
Noticed Alternative Routes

April 2015

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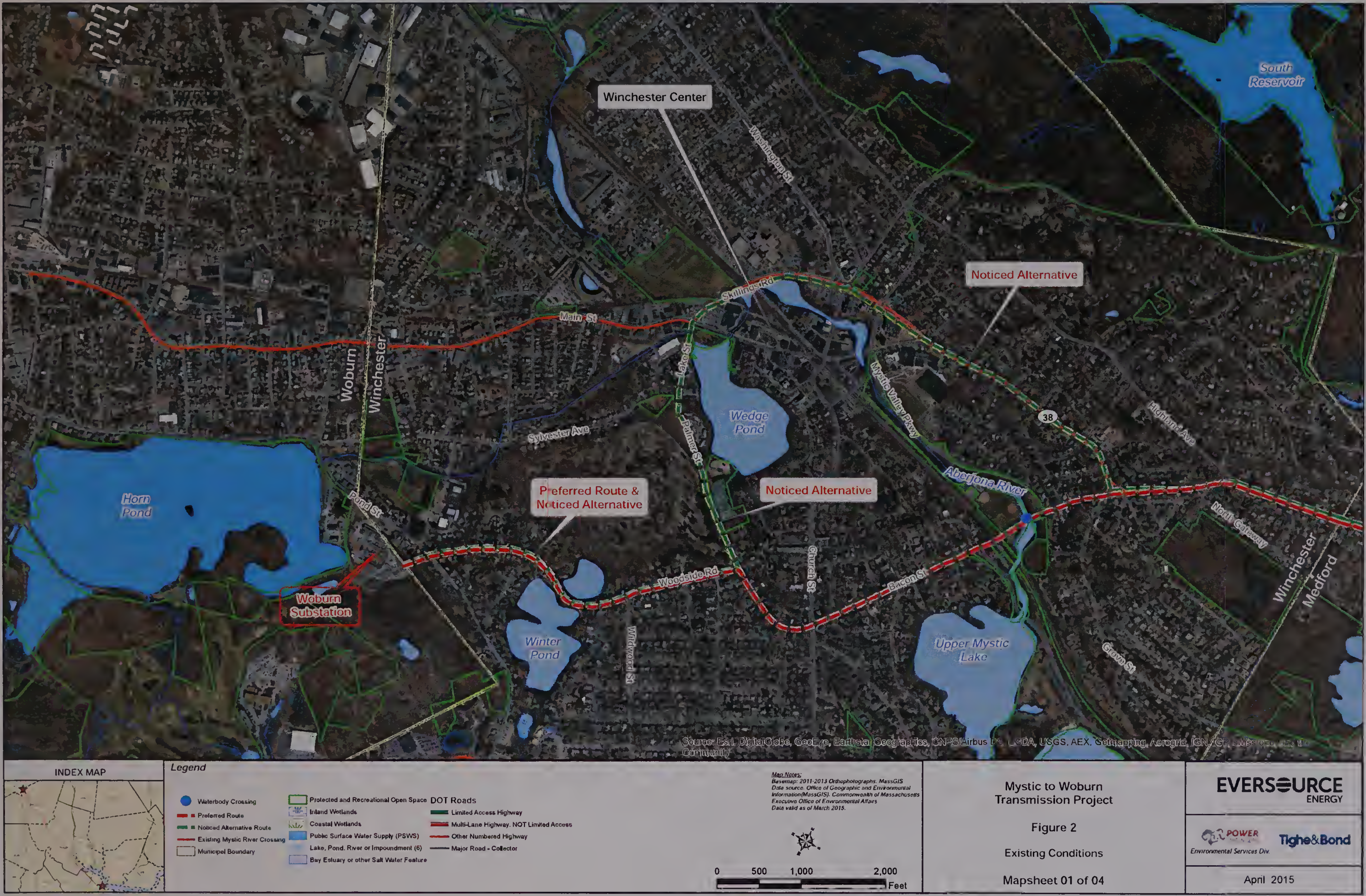
South Reservoir
Winchester Center
Noticed Alternative
Washington St
Skillings Rd
Main St
Woburn
Winchester
Lake St
Wedge Pond
Mystic Valley Pkwy
38
Highland Ave
Palmer St
Sylvester Ave
Aberjona River
Horn Pond
Pond St
Preferred Route & Noticed Alternative
Noticed Alternative
North Gateway
Winchester
Medford
Woburn Substation
Woodside Rd
Church St
Bacon St
Winter Pond
Wildwood St
Upper Mystic Lake
Grove St
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Existing Mystic River Crossing
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Protected and Recreational Open Space
Inland Wetlands
Coastal Wetlands
Public Surface Water Supply (PSWS)
Lake, Pond, River or Impoundment (6)
Bay Estuary or other Salt Water Feature
DOT Roads
Limited Access Highway
Multi-Lane Highway, NOT Limited Access
Other Numbered Highway
Major Road - Collector
0
500
1,000
2,000
Feet

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

Map Notes:
Basemap: 2011-2013 Orthophotographs. MassGIS
Data source. Office of Geographic and Environmental Information(MassGIS). Commonwealth of Massachusetts Executive Office of Environmental Affairs
Data valid as of March 2015.

Mystic to Woburn
Transmission Project

Figure 2

Existing Conditions

Mapsheet 01 of 04

EVERSOURCE ENERGY

POWER Environmental Services Div.

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April 2015

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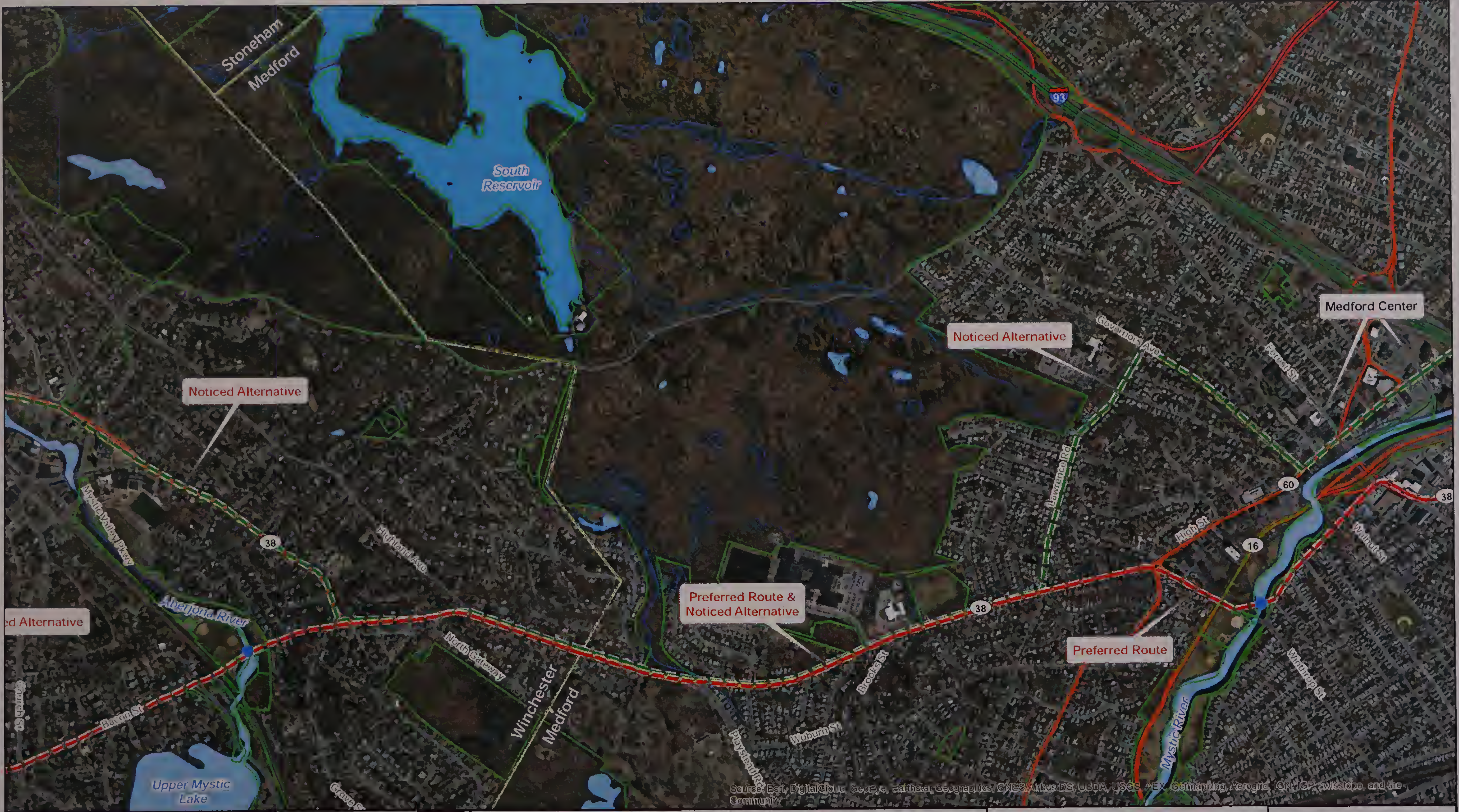
Stoneham
Medford
South Reservoir
93
Medford Center
Noticed Alternative
Governors Ave
Forest St
Noticed Alternative
Lawrence Rd
60
38
High St
16
Walnut St
Mystic River
Winthrop St
Preferred Route
38
Preferred Route & Noticed Alternative
Brooks St
Woburn St
Playstead Rd
Winchester
Medford
North Gateway
Highland Ave
38
Mystic Valley Pkwy
Aberjona River
ed Alternative
Bacon St
Church St
Upper Mystic Lake
Grove St

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

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Legend

- ● Waterbody Crossing
- Preferred Route
- Noticed Alternative Route
- Existing Mystic River Crossing
- Municipal Boundary
- Protected and Recreational Open Space
- Inland Wetlands
- Coastal Wetlands
- Public Surface Water Supply (PSWS)
- Lake, Pond, River or Impoundment (6)
- Bay Estuary or other Salt Water Feature

DOT Roads

- Limited Access Highway
- Multi-Lane Highway, NOT Limited Access
- Other Numbered Highway
- Major Road - Collector

Map Notes:
Basemap: 2011-2013 Orthophotographs. MassGIS
Data source. Office of Geographic and Environmental Information(MassGIS). Commonwealth of Massachusetts Executive Office of Environmental Affairs.
Data valid as of March 2015.

0 500 1,000 2,000
Feet

Mystic to Woburn Transmission Project

Figure 2

Existing Conditions

Mapsheet 02 of 04

EVERSOURCE ENERGY

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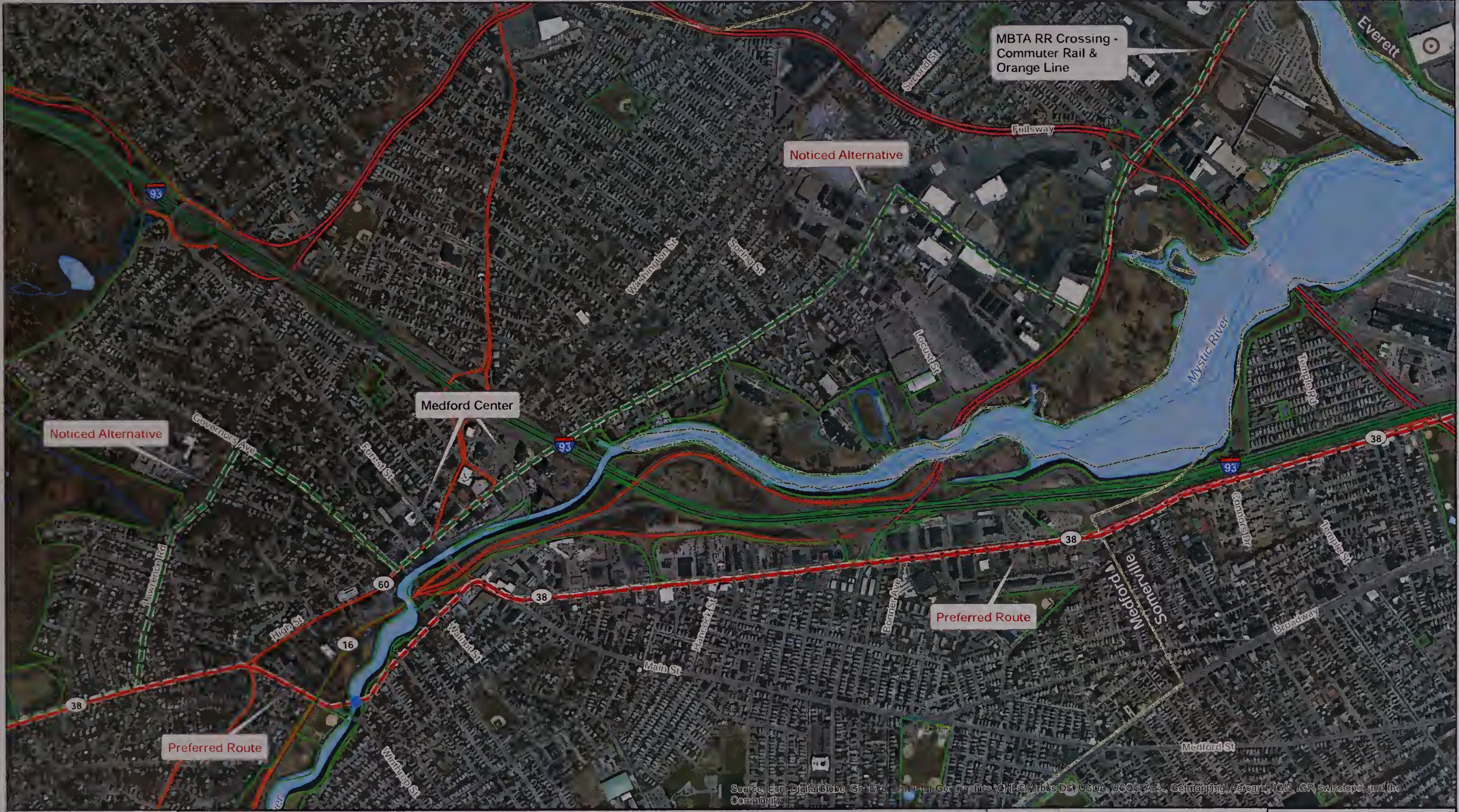
MBTA RR Crossing -
Commuter Rail &
Orange Line
Everett
Noticed Alternative
Fellsway
Second St
Washington St
Spring St
Locust St
Mystic River
Temple Rd
Medford Center
Noticed Alternative
Governors Ave
Forest St
93
93
93
38
38
38
38
60
16
Lawrence Rd
High St
Walnut St
Winthrop St
Main St
Hancock St
Bonner Ave
Preferred Route
Preferred Route
Medford
Somerville
Connors Dr
Temple St
Broadway
Medford St

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the Community

INDEX MAP

Legend

● Waterbody Crossing
🟥 Preferred Route
🟩 Noticed Alternative Route
— Existing Mystic River Crossing
☐ Municipal Boundary

☐ Protected and Recreational Open Space
Inland Wetlands
Coastal Wetlands
Public Surface Water Supply (PSWS)
Lake, Pond, River or Impoundment (6)
Bay Estuary or other Salt Water Feature

DOT Roads
🟩 Limited Access Highway
🟥 Multi-Lane Highway, NOT Limited Access
— Other Numbered Highway
— Major Road - Collector

Map Notes:
Basemap: 2011-2013 Orthophotographs, MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS), Commonwealth of Massachusetts Executive Office of Environmental Affairs
Data valid as of March 2015.

0 500 1,000 2,000 Feet

Mystic to Woburn
Transmission Project

Figure 2

Existing Conditions

Mapsheet 03 of 04

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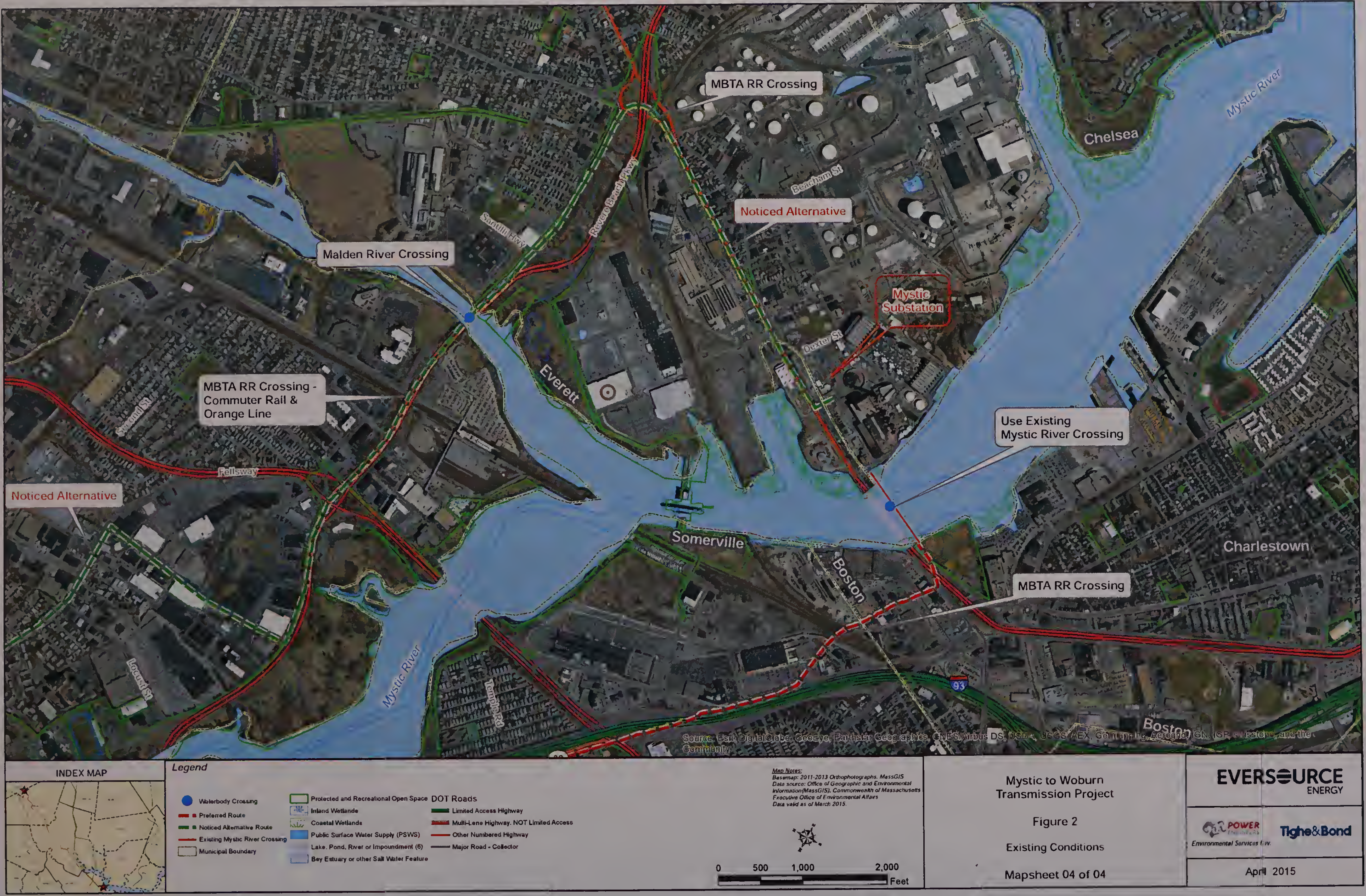
MBTA RR Crossing
Noticed Alternative
Mystic Substation
Use Existing Mystic River Crossing
MBTA RR Crossing
Malden River Crossing
MBTA RR Crossing - Commuter Rail & Orange Line
Noticed Alternative
Chelsea
Mystic River
Charlestown
Everett
Somerville
Boston
Boston
Mystic River
Beacham St
Dexter St
Santilli Hwy
Revere Beach Pkwy
Fellsway
Second St
Locust St
Temple Rd
93
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Preferred Route
Noticed Alternative Route
Existing Mystic River Crossing
Municipal Boundary
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Inland Wetlands
Coastal Wetlands
Public Surface Water Supply (PSWS)
Lake, Pond, River or Impoundment (6)
Bay Estuary or other Salt Water Feature
DOT Roads
Limited Access Highway
Multi-Lane Highway, NOT Limited Access
Other Numbered Highway
Major Road - Collector
0
500
1,000
2,000
Feet

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the Community

Map Notes:
Basemap: 2011-2013 Orthophotographs. MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS), Commonwealth of Massachusetts Executive Office of Environmental Affairs
Data valid as of March 2015.

Mystic to Woburn
Transmission Project

Figure 2

Existing Conditions

Mapsheet 04 of 04

EVERSOURCE ENERGY

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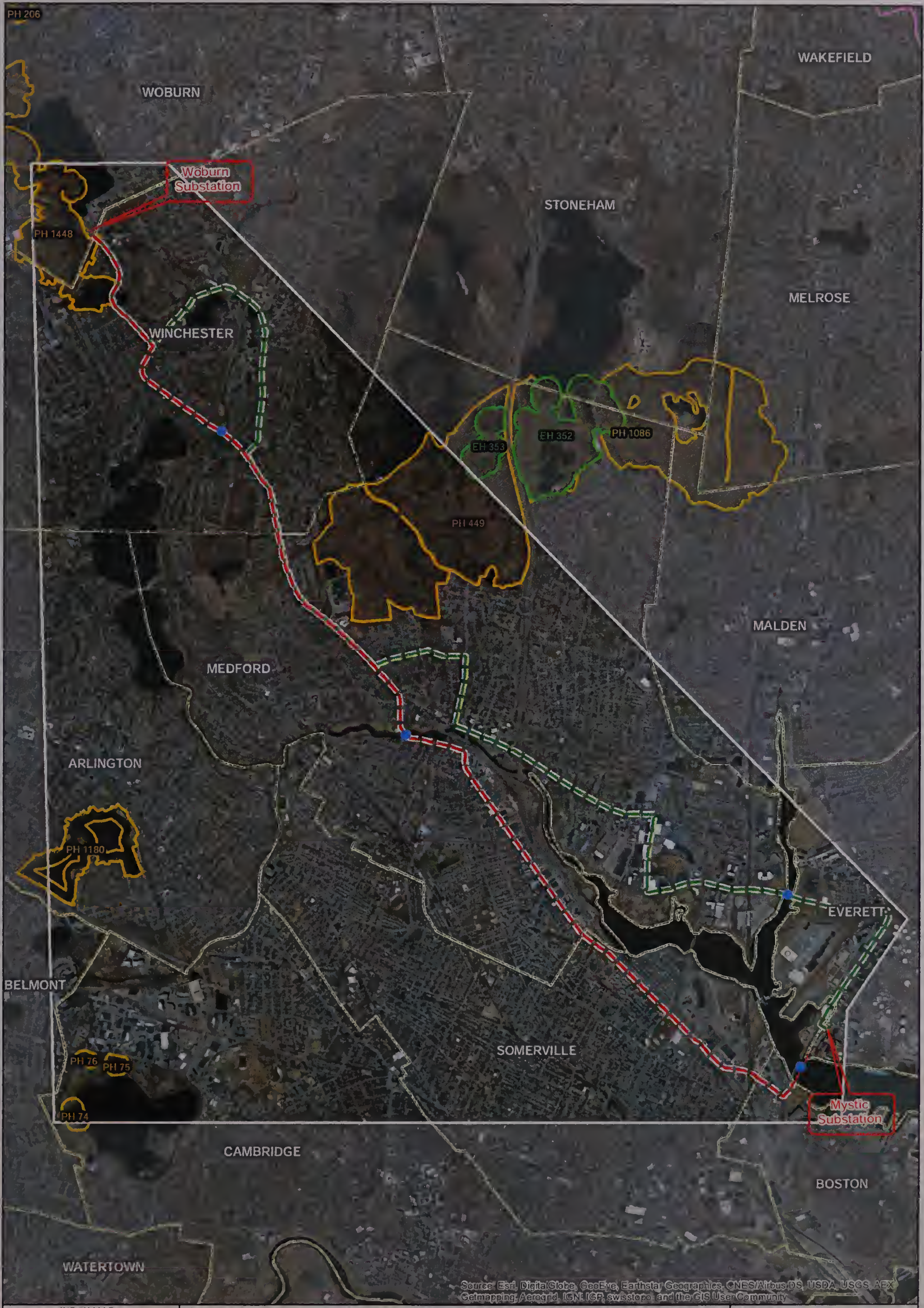
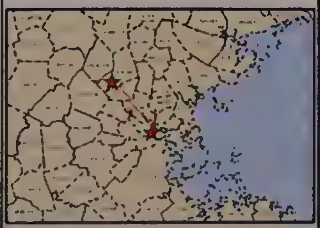

PH 206
WAKEFIELD
WOBURN
Woburn Substation
STONEHAM
PH 1448
MELROSE
WINCHESTER
EH 353
EH 352
PH 1086
PH 449
MALDEN
MEDFORD
ARLINGTON
PH 1180
EVERETT
BELMONT
SOMERVILLE
PH 76
PH 75
PH 74
Mystic Substation
CAMBRIDGE
BOSTON
WATERTOWN

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

INDEX MAP



Map Notes:
Basemap: USGS Quadrangle Basemap, MassGIS

Legend

●	Waterbody Crossing
🟥	Preferred Route
🟩	Noticed Alternative Route
🟥	Existing Mystic River Crossing
☐	Municipal Boundary
▨	Outside Study Area
☐	Area of Critical Environmental Concern (ACEC)
🟩	NHESP Estimated Habitats for Rare Wildlife
🟨	NHESP Priority Habitats for Rare Species

Mystic to Woburn
Transmission Project

Figure 3

ACEC and Rare Species

0 1,000 2,000 4,000
Feet

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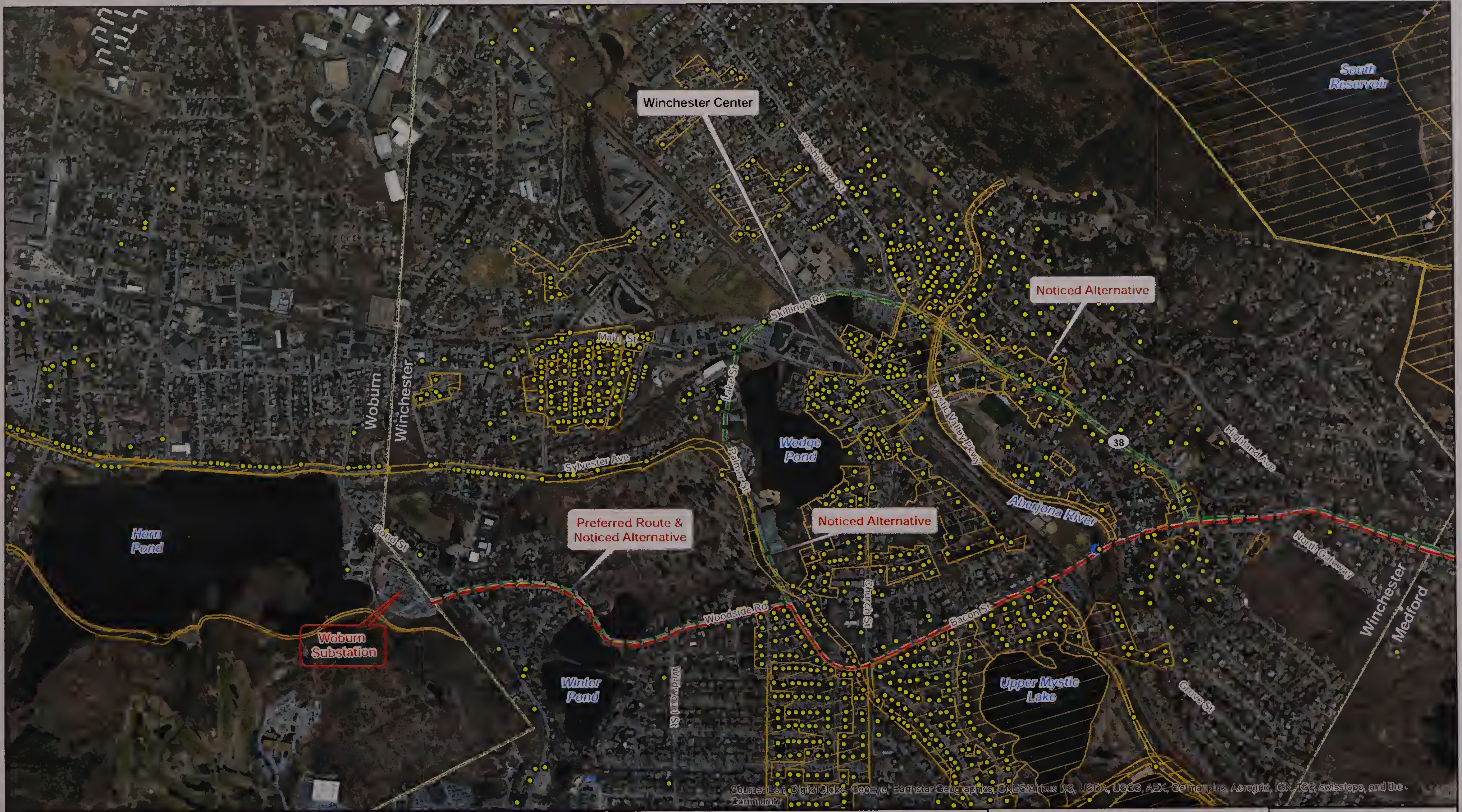
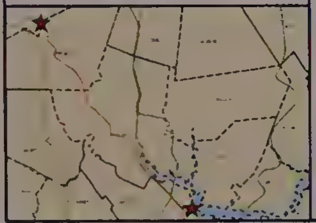

South Reservoir
Winchester Center
Noticed Alternative
Washington St
Skillings Rd
Main St
Lake St
Mystic Valley Pkwy
38
Highland Ave
Woburn
Winchester
Sylvester Ave
Wedge Pond
Palmer St
Aberjona River
Horn Pond
Pond St
Preferred Route & Noticed Alternative
Noticed Alternative
North Gateway
Winchester
Medford
Woburn Substation
Woodside Rd
Church St
Bacon St
Winter Pond
Wildwood St
Upper Mystic Lake
Grove St

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

INDEX MAP



Legend

- ● Waterbody Crossing
- 🟥 Preferred Route
- 🟩 Noticed Alternative Route
- 🟥 Existing Mystic River Crossing
- ☐ Municipal Boundary
- ● Historic Point
- ☐ Historic Area

Map Notes:
Basemap: 2011-2013 Orthophotographs. MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS). Commonwealth of Massachusetts Executive Office of Environmental Affairs
Data valid as of March 2015

0 500 1,000 2,000 Feet

Mystic to Woburn
Transmission Project

Figure 4

Historical Resources

Mapsheet 01 of 04

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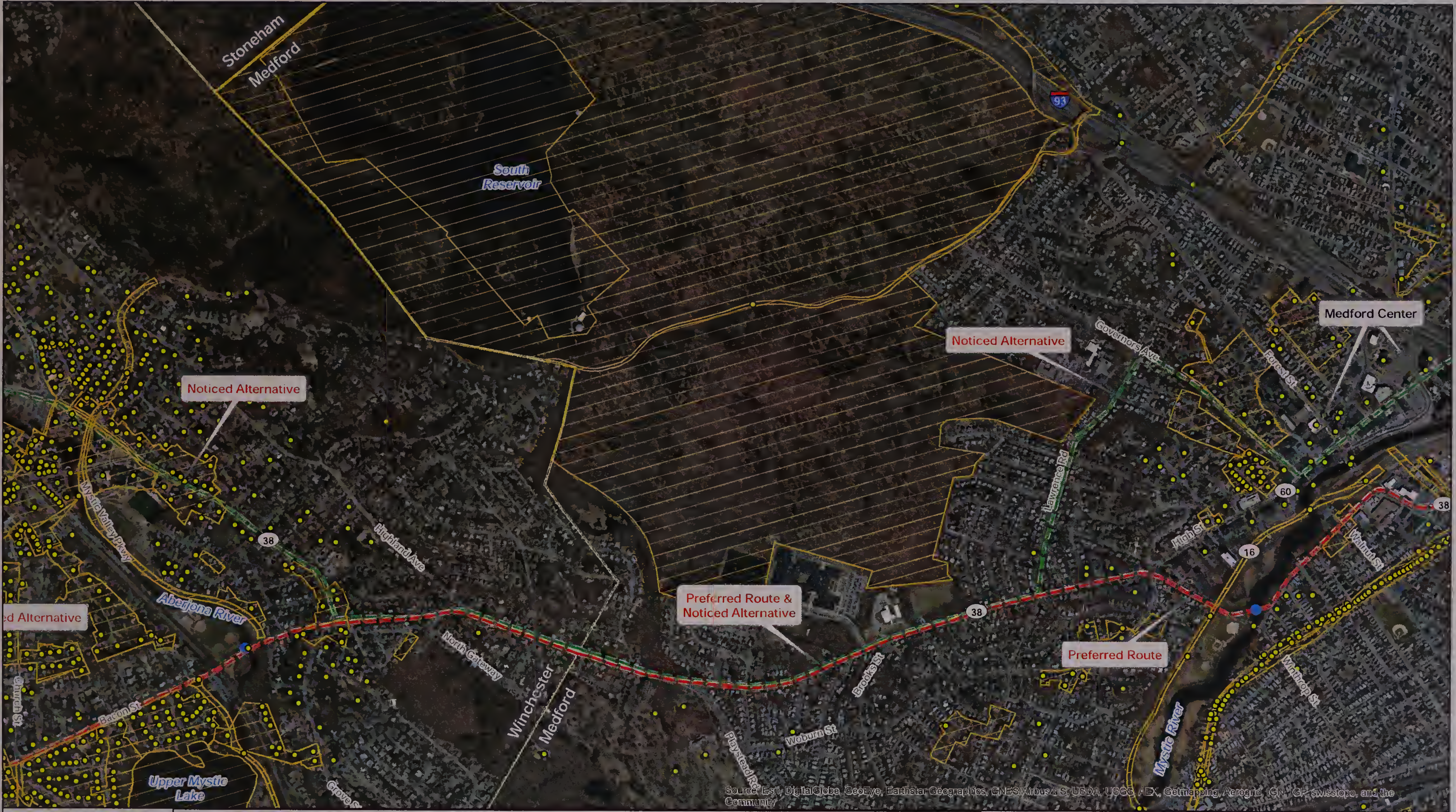
Stoneham
Medford
93
South Reservoir
Medford Center
Noticed Alternative
Governors Ave
Forest St
Noticed Alternative
d Alternative
Mystic Valley Pkwy
38
Highland Ave
Aberjona River
60
Lawrence Rd
High St
16
38
Walnut St
Preferred Route & Noticed Alternative
38
Preferred Route
North Gateway
Winchester
Medford
Brooks St
Church St
Bacon St
Upper Mystic Lake
Grove St
Playstead Rd
Woburn St
Mystic River
Winthrop St

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the Community

INDEX MAP

Legend

- ● Waterbody Crossing
- Preferred Route
- Noticed Alternative Route
- Existing Mystic River Crossing
- ☐ Municipal Boundary
- ● Historic Point
- ☐ Historic Area

Map Notes:
Basemap: 2011-2013 Orthophotographs. MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS), Commonwealth of Massachusetts Executive Office of Environmental Affairs
Data valid as of March 2015.

0 500 1,000 2,000 Feet

Mystic to Woburn
Transmission Project

Figure 4

Historical Resources

Mapsheet 02 of 04

EVERSOURCE ENERGY

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April 2015

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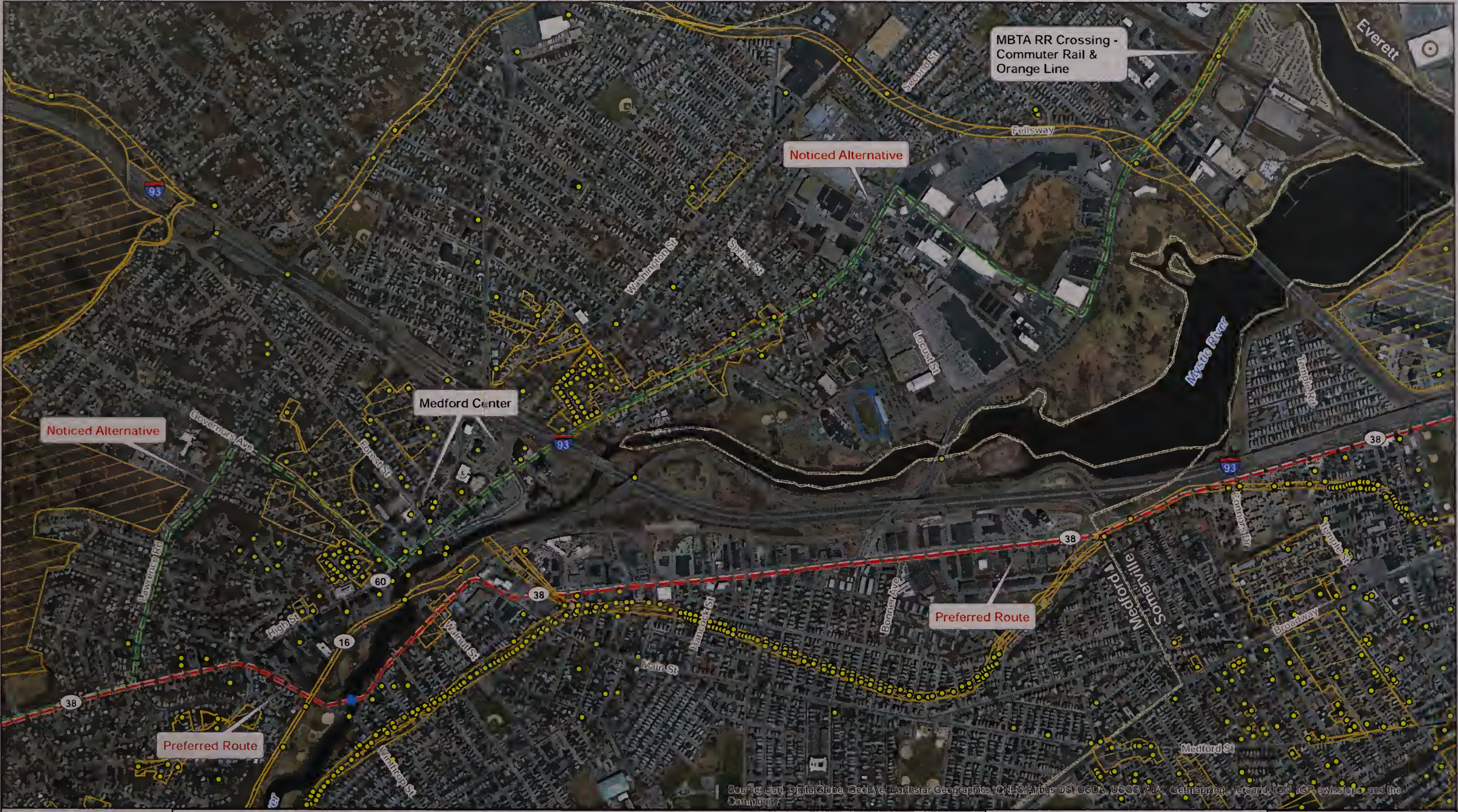
Everett
MBTA RR Crossing - Commuter Rail & Orange Line
Fellsway
Second St
Noticed Alternative
Washington St
Spring St
Locust St
Mystic River
Temple Rd
Medford Center
93
38
Noticed Alternative
Governors Ave
Forest St
Lawrence Rd
High St
60
16
38
Walnut St
Hancock St
Main St
Bonner Ave
Preferred Route
Medford
Somerville
Connors Dr
Temple St
Broadway
Medford St
Winthrop St
Preferred Route
38

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the Community

INDEX MAP

Legend

- ● Waterbody Crossing
- Preferred Route
- Noticed Alternative Route
- Existing Mystic River Crossing
- ☐ Municipal Boundary
- ● Historic Point
- ☐ Historic Area

Map Notes:
Basemap: 2011-2013 Orthophotographs. MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS). Commonwealth of Massachusetts Executive Office of Environmental Affairs
Data valid as of March 2015.

0 500 1,000 2,000 Feet

Mystic to Woburn
Transmission Project

Figure 4

Historical Resources

Mapsheet 03 of 04

EVERSOURCE ENERGY

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April 2015

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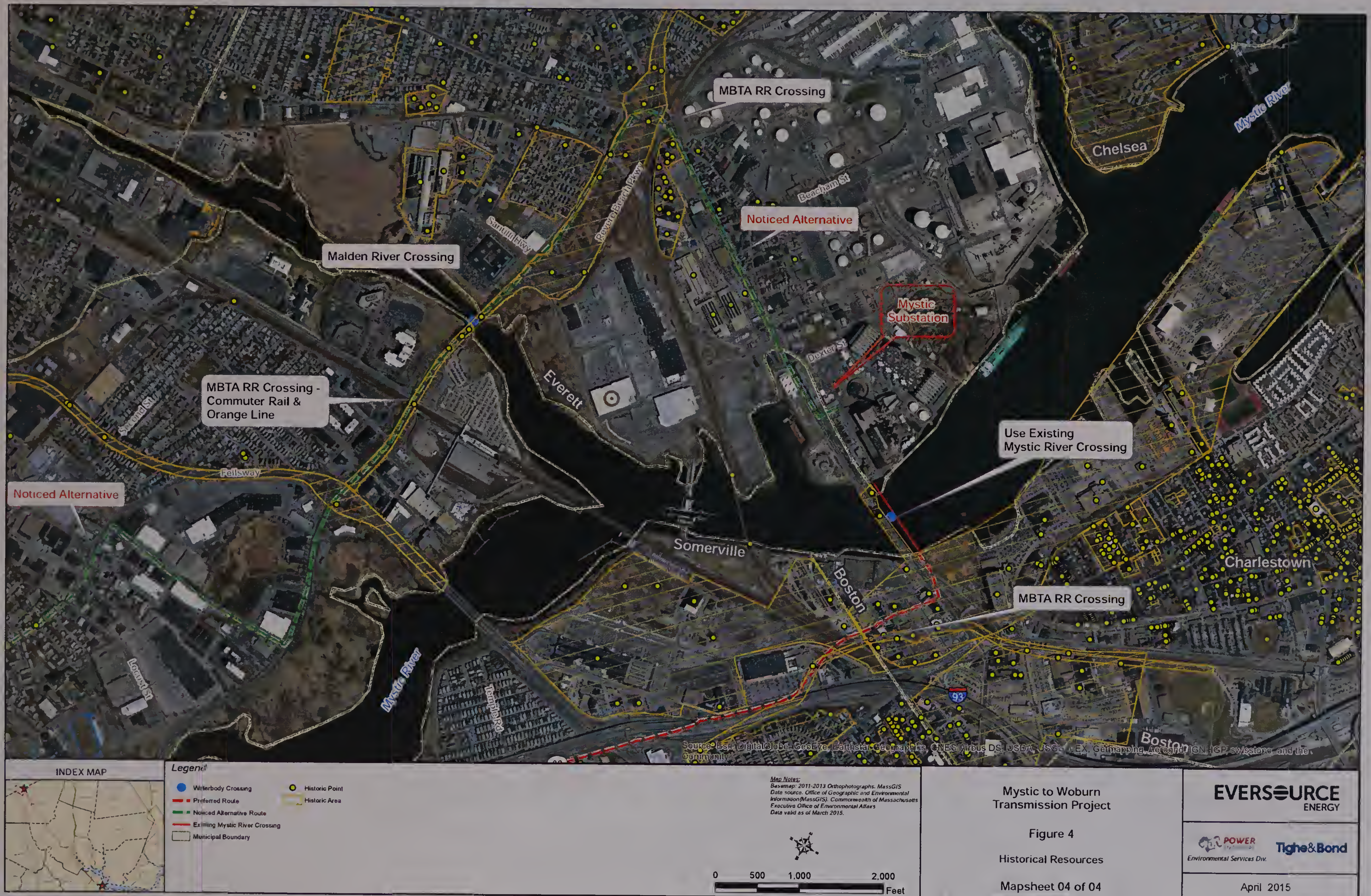
MBTA RR Crossing
Chelsea
Mystic River
Beacham St
Noticed Alternative
Malden River Crossing
Santilli Hwy
Revere Beach Pkwy
Mystic Substation
Dexter St
Everett
MBTA RR Crossing - Commuter Rail & Orange Line
Second St
Use Existing Mystic River Crossing
Fellsway
Noticed Alternative
Somerville
Boston
Charlestown
MBTA RR Crossing
Locust St
Mystic River
Temple Rd
93
Boston
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Preferred Route
Noticed Alternative Route
Existing Mystic River Crossing
Municipal Boundary
Historic Point
Historic Area
0
500
1,000
2,000
Feet

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

Map Notes:
Basemap: 2011-2013 Orthophotographs. MassGIS
Data source. Office of Geographic and Environmental Information(MassGIS). Commonwealth of Massachusetts Executive Office of Environmental Affairs
Data valid as of March 2015.

Mystic to Woburn
Transmission Project

Figure 4

Historical Resources

Mapsheet 04 of 04

EVERSOURCE ENERGY

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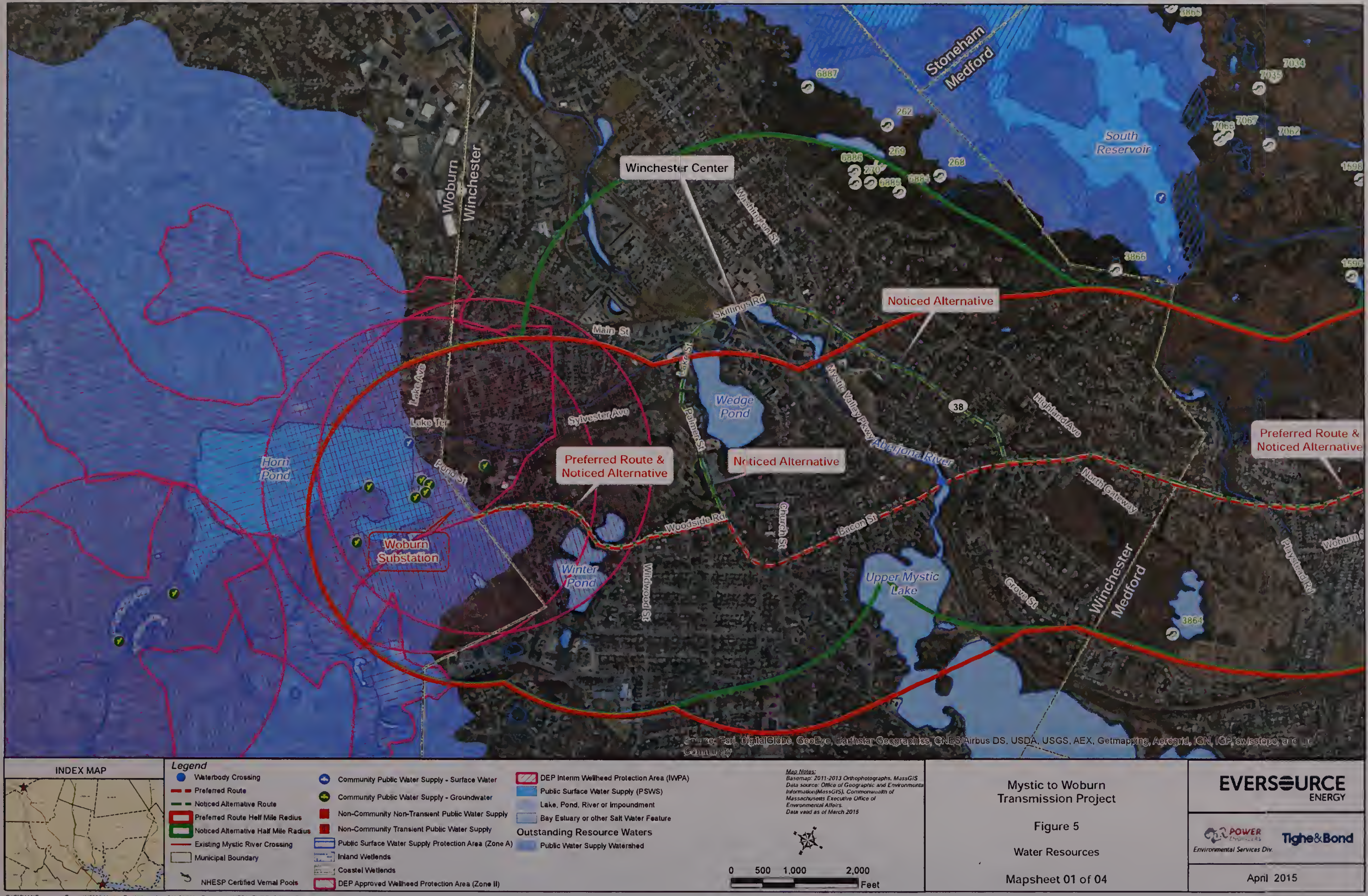
Woburn
Winchester
Stoneham
Medford
South Reservoir
Winchester Center
Noticed Alternative
Preferred Route & Noticed Alternative
Horn Pond
Wedge Pond
Winter Pond
Upper Mystic Lake
Woburn Substation
Washington St
Skillings Rd
Main St
Lake Ave
Lake Ter
Pond St
Sylvester Ave
Palmer St
Lake St
Woodside Rd
Church St
Wildwood St
Bacon St
Mystic Valley Pkwy
Aberjona River
Highland Ave
North Gateway
Grove St
Playstead Rd
38
6887
262
269
268
6886
270
6885
6884
3865
3866
3864
7034
7035
7065
7067
7062
1598
Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
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Preferred Route Half Mile Radius
Noticed Alternative Half Mile Radius
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NHESP Certified Vernal Pools
Community Public Water Supply - Surface Water
Community Public Water Supply - Groundwater
Non-Community Non-Transient Public Water Supply
Non-Community Transient Public Water Supply
Public Surface Water Supply Protection Area (Zone A)
Inland Wetlands
Coastal Wetlands
DEP Approved Wellhead Protection Area (Zone II)
DEP Interim Wellhead Protection Area (IWPA)
Public Surface Water Supply (PSWS)
Lake, Pond, River or Impoundment
Bay Estuary or other Salt Water Feature
Outstanding Resource Waters
Public Water Supply Watershed
0
500
1,000
2,000
Feet

Map Notes:
Basemap: 2011-2013 Orthophotographs, MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS), Commonwealth of Massachusetts Executive Office of Environmental Affairs.
Data valid as of March 2015

Mystic to Woburn
Transmission Project

Figure 5

Water Resources

Mapsheet 01 of 04

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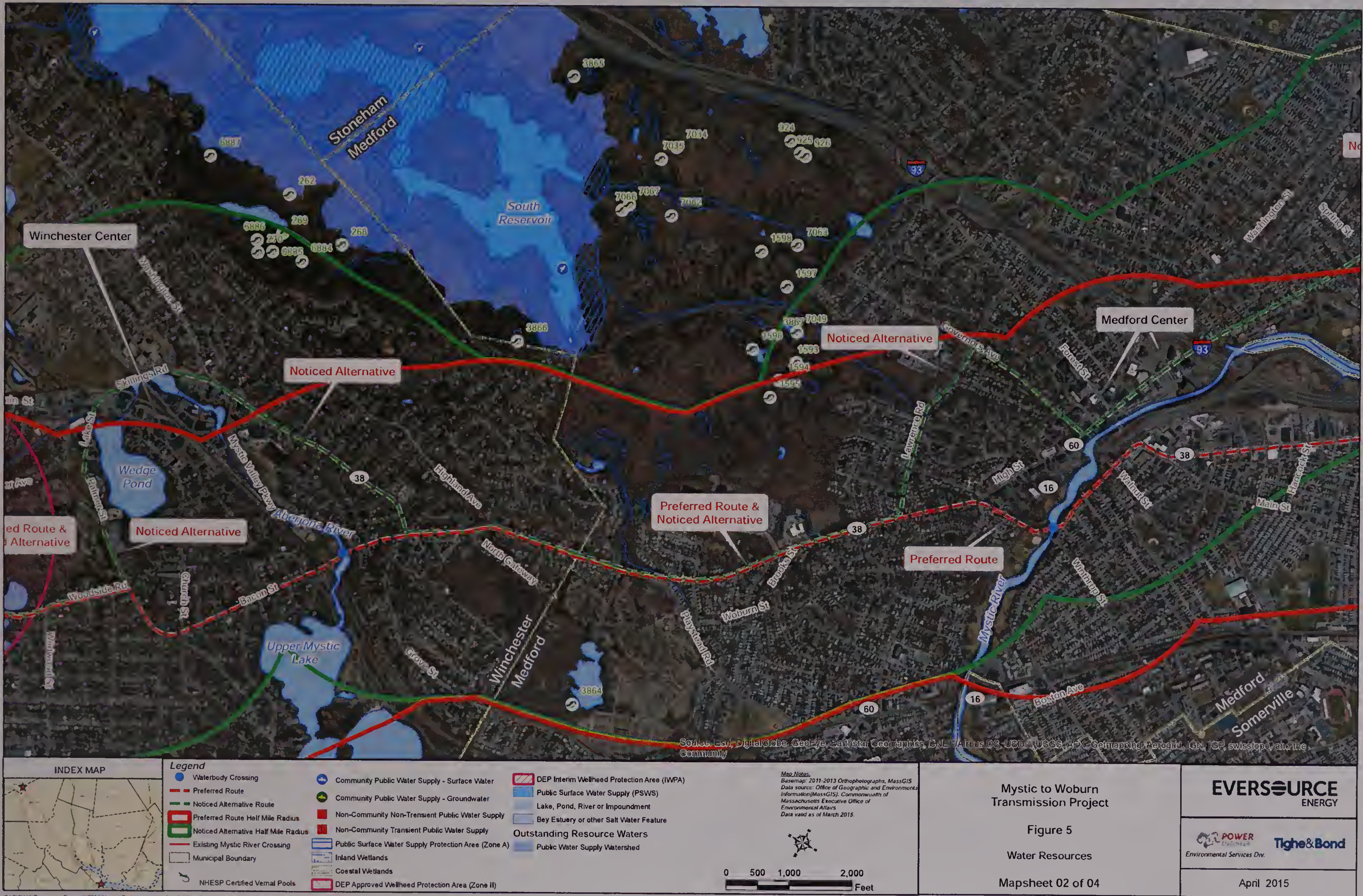
Winchester Center
Medford Center
Noticed Alternative
Noticed Alternative
Noticed Alternative
Preferred Route & Noticed Alternative
Preferred Route
ed Route &
l Alternative
No
Stoneham
Medford
South Reservoir
Winchester
Medford
Medford
Somerville
Wedge Pond
Upper Mystic Lake
Mystic River
Aberjona River
Mystic Valley Pkwy
Skillings Rd
Washington St
Highland Ave
North Gateway
Grove St
Bacon St
Woodside Rd
Church St
Palmer St
Lake St
Brooks St
Woburn St
Playstead Rd
Lawrence Rd
Governors Ave
Forest St
High St
Walnut St
Winthrop St
Main St
Hancock St
Spring St
Boston Ave
Wildwood St
93
38
60
16
3865
5887
262
269
266
6886
270
6885
6884
3866
7034
7035
7067
7066
7062
924
925
926
7063
1598
1597
7049
3867
1596
1593
1594
1595
3864
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Noticed Alternative Route
Preferred Route Half Mile Radius
Noticed Alternative Half Mile Radius
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NHESP Certified Vernal Pools
Community Public Water Supply - Surface Water
Community Public Water Supply - Groundwater
Non-Community Non-Transient Public Water Supply
Non-Community Transient Public Water Supply
Public Surface Water Supply Protection Area (Zone A)
Inland Wetlands
Coastal Wetlands
DEP Approved Wellhead Protection Area (Zone II)
DEP Interim Wellhead Protection Area (IWPA)
Public Surface Water Supply (PSWS)
Lake, Pond, River or Impoundment
Bay Estuary or other Salt Water Feature
Outstanding Resource Waters
Public Water Supply Watershed
0
500
1,000
2,000
Feet

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

Map Notes.
Basemap: 2011-2013 Orthophotographs, MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS). Commonwealth of Massachusetts Executive Office of Environmental Affairs
Data valid as of March 2015.

Mystic to Woburn
Transmission Project

Figure 5

Water Resources

Mapsheet 02 of 04

EVERSOURCE ENERGY

POWER Environmental Services Div.

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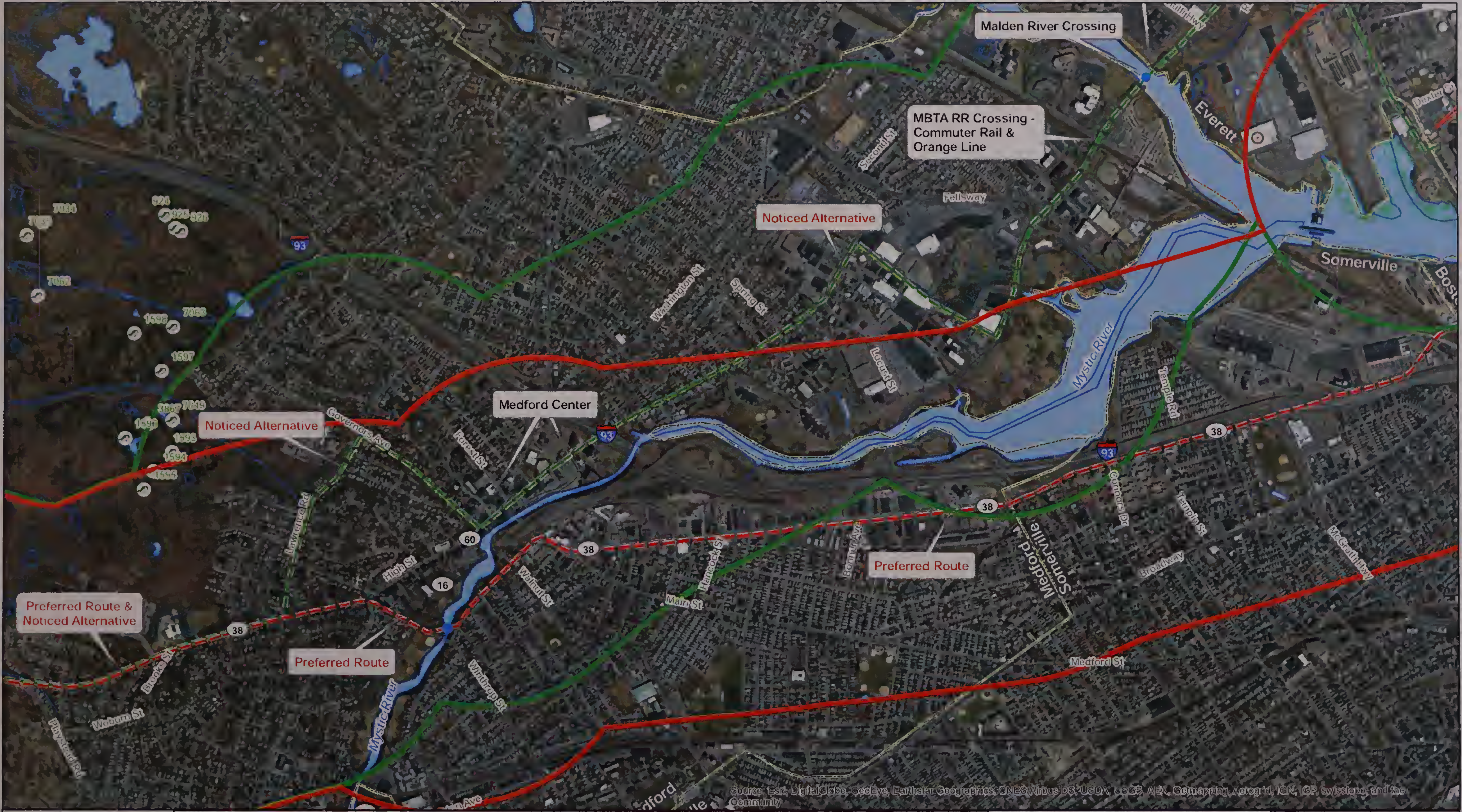
Malden River Crossing
MBTA RR Crossing - Commuter Rail & Orange Line
Noticed Alternative
Medford Center
Noticed Alternative
Preferred Route
Preferred Route
Preferred Route & Noticed Alternative
Everett
Somerville
Medford
Somerville
Mystic River
Mystic River
Fellsway
Second St
Washington St
Spring St
Locust St
Temple Rd
Connors Dr
Temple St
Broadway
McGrath Hwy
Medford St
Bonner Ave
Hancock St
Main St
Walnut St
Winthrop St
High St
Forest St
Governors Ave
Lawrence Rd
Brooks St
Woburn St
Playstead Rd
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1594
1595

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

INDEX MAP

Legend

- ● Waterbody Crossing
- Preferred Route
- Noticed Alternative Route
- Preferred Route Half Mile Radius
- Noticed Alternative Half Mile Radius
- Existing Mystic River Crossing
- ☐ Municipal Boundary
- NHESP Certified Vernal Pools
- Community Public Water Supply - Surface Water
- Community Public Water Supply - Groundwater
- Non-Community Non-Transient Public Water Supply
- Non-Community Transient Public Water Supply
- Public Surface Water Supply Protection Area (Zone A)
- Inland Wetlands
- Coastal Wetlands
- DEP Approved Wellhead Protection Area (Zone II)
- DEP Interim Wellhead Protection Area (IWPA)
- Public Surface Water Supply (PSWS)
- Lake, Pond, River or Impoundment
- Bay Estuary or other Salt Water Feature

Outstanding Resource Waters

- Public Water Supply Watershed

Map Notes:
Basemap: 2011-2013 Orthophotographs, MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS), Commonwealth of Massachusetts Executive Office of Environmental Affairs.
Data valid as of March 2015.

0 500 1,000 2,000 Feet

Mystic to Woburn
Transmission Project

Figure 5

Water Resources

Mapsheet 03 of 04

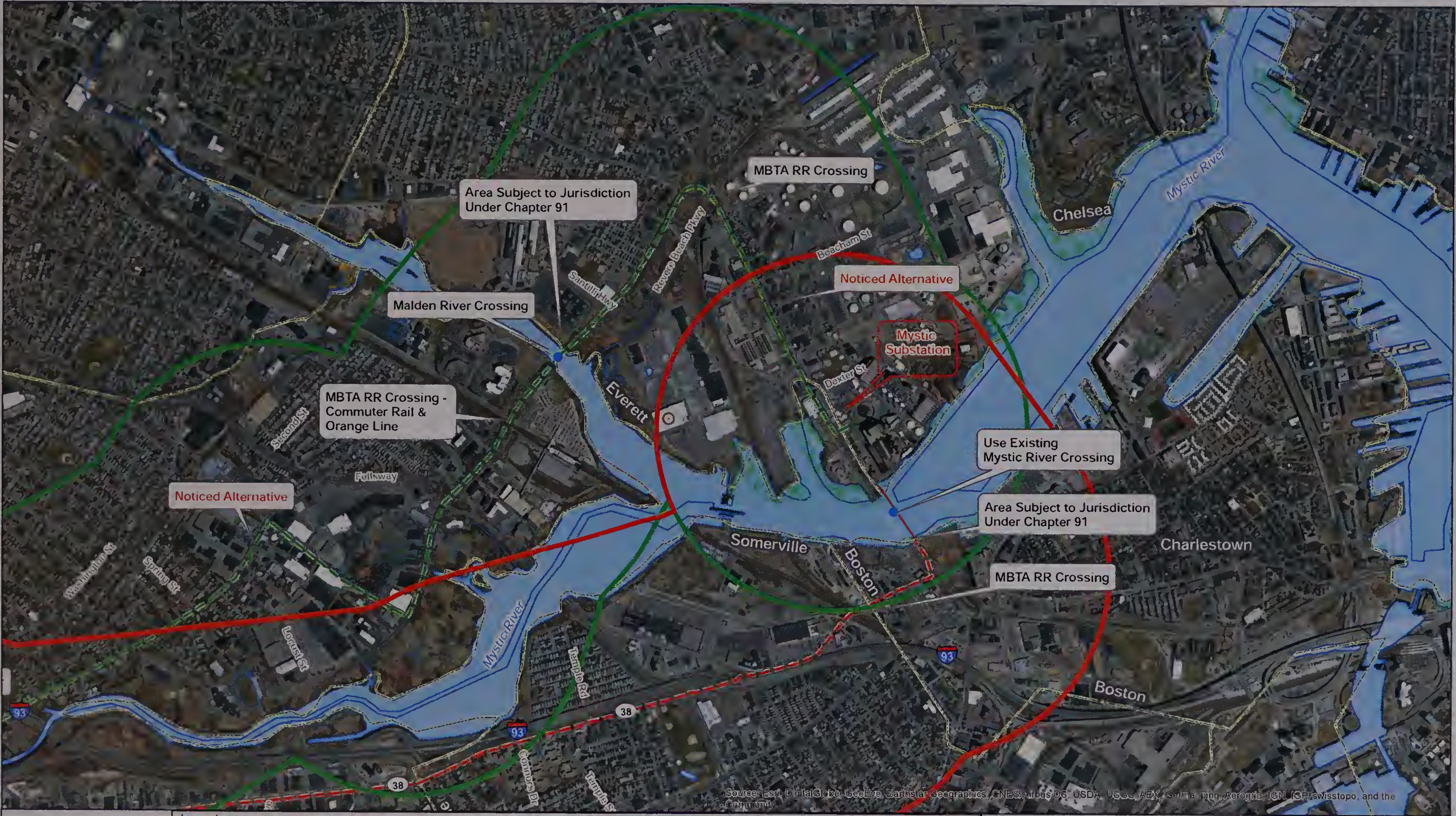
EVERSOURCE
ENERGY

POWER
Environmental Services Div

Tighe&Bond

April 2015

G:\GIS\MA\EversourceEnergy\N0996\Mystic_To_Woburn_Line211-514\MapDocuments\MEPA_ENF\Fig5_WaterResources.mxd


Area Subject to Jurisdiction Under Chapter 91
MBTA RR Crossing
Chelsea
Mystic River
Beacham St
Revere Beach Pkwy
Santilli Hwy
Noticed Alternative
Mystic Substation
Malden River Crossing
Dexter St
Everett
MBTA RR Crossing - Commuter Rail & Orange Line
Second St
Fellsway
Noticed Alternative
Use Existing Mystic River Crossing
Area Subject to Jurisdiction Under Chapter 91
Charlestown
Somerville
Boston
MBTA RR Crossing
Washington St
Spring St
Locust St
Mystic River
Temple Rd
Temple St
Connors Dr
93
38
Boston

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the
Community

INDEX MAP

Legend

● Waterbody Crossing
Preferred Route
Noticed Alternative Route
Preferred Route Half Mile Radius
Noticed Alternative Half Mile Radius
Existing Mystic River Crossing
Municipal Boundary
NHESP Certified Vernal Pools
Community Public Water Supply - Surface Water
Community Public Water Supply - Groundwater
Non-Community Non-Transient Public Water Supply
Non-Community Transient Public Water Supply
Public Surface Water Supply Protection Area (Zone A)
Inland Wetlands
Coastal Wetlands
DEP Approved Wellhead Protection Area (Zone II)
DEP Interim Wellhead Protection Area (IWPA)
Public Surface Water Supply (PSWS)
Lake, Pond, River or Impoundment
Bay Estuary or other Salt Water Feature

Outstanding Resource Waters

Public Water Supply Watershed

Map Notes:
Basemap: 2011-2013 Orthophotographs. MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS), Commonwealth of Massachusetts Executive Office of Environmental Affairs
Data valid as of March 2015

0 500 1,000 2,000 Feet

Mystic to Woburn Transmission Project

Figure 5

Water Resources

Mapsheet 04 of 04

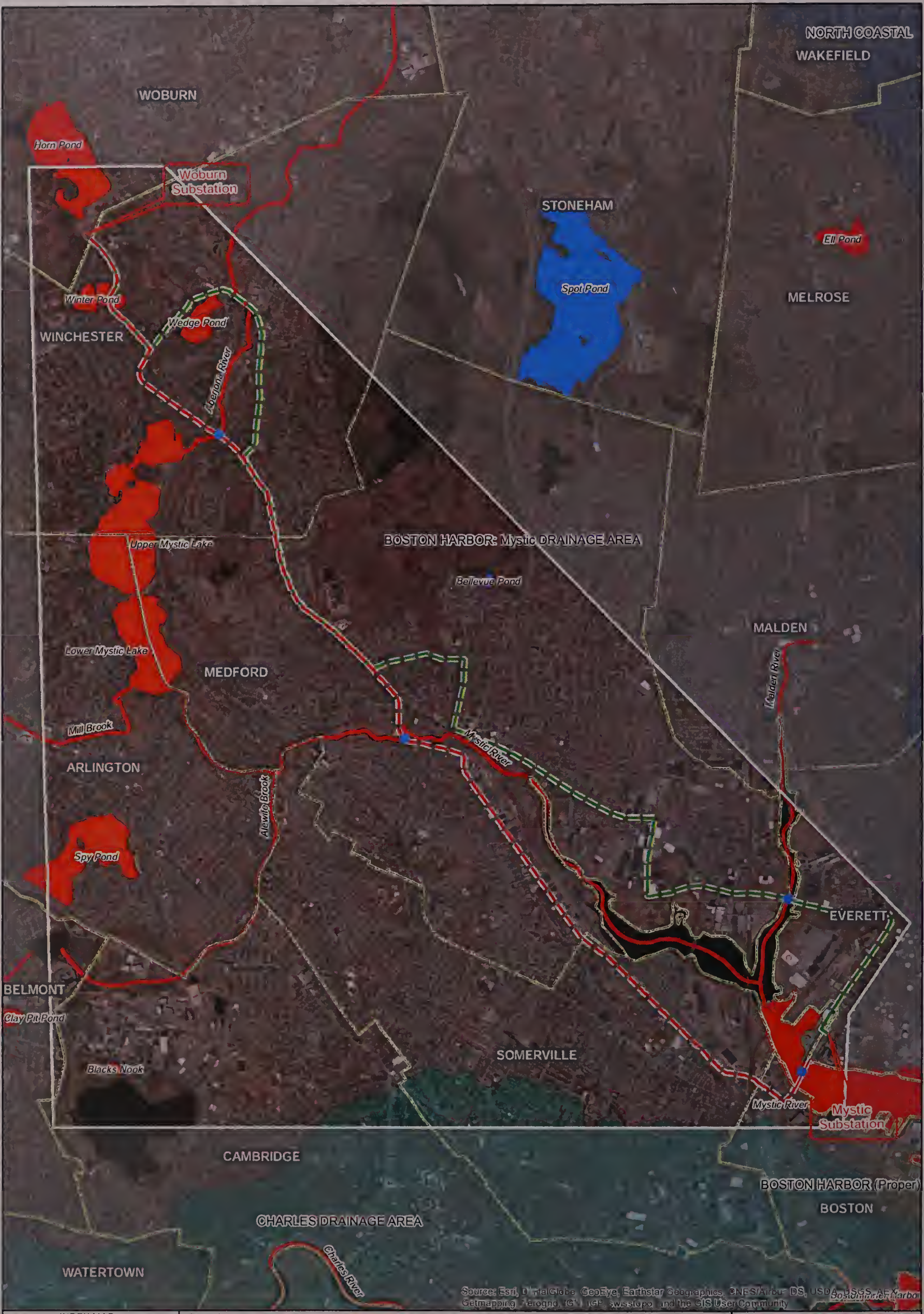
EVERSOURCE ENERGY

POWER Engineers
Environmental Services Div.

Tighe&Bond

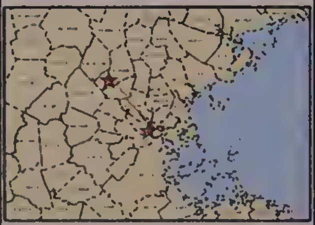
April 2015

G:\GIS\MA\EversourceEnergy\N0998\Mystic_To_Woburn_Line211-514\MapDocuments\MEPA_ENF\Fig5_WaterResources.mxd


NORTH COASTAL
WAKEFIELD
WOBURN
Horn Pond
Woburn Substation
STONEHAM
Ell Pond
Spot Pond
MELROSE
Winter Pond
Wedge Pond
WINCHESTER
Aberjona River
Upper Mystic Lake
BOSTON HARBOR: Mystic DRAINAGE AREA
Bellevue Pond
MALDEN
Malden River
Lower Mystic Lake
MEDFORD
Mill Brook
Mystic River
ARLINGTON
Alewife Brook
Spy Pond
EVERETT
BELMONT
Clay Pit Pond
SOMERVILLE
Blacks Nook
Mystic River
Mystic Substation
CAMBRIDGE
BOSTON HARBOR (Proper)
BOSTON
CHARLES DRAINAGE AREA
WATERTOWN
Charles River
Boston Inner Harbor

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

INDEX MAP



Map Notes:
Basemap: USGS Quadrangle Basemap, MassGIS

Legend

● Waterbody Crossing
Preferred Route
Noticed Alternative Route
Existing Mystic River Crossing
Municipal Boundary

Water Body Segments - Rivers
5 - Impaired - TMDL required

Water Body Segments - Lakes, Estuaries
🟦 3 - No uses assessed
🟥 5 - Impaired - TMDL required

River Basin and Coastal Drainage Area
BOSTON HARBOR: Mystic
CHARLES
BOSTON HARBOR (Proper)
NORTH COASTAL

Mystic to Woburn
Transmission Project

Figure 6

Impaired Waterbodies

0 1,000 2,000 4,000
Feet

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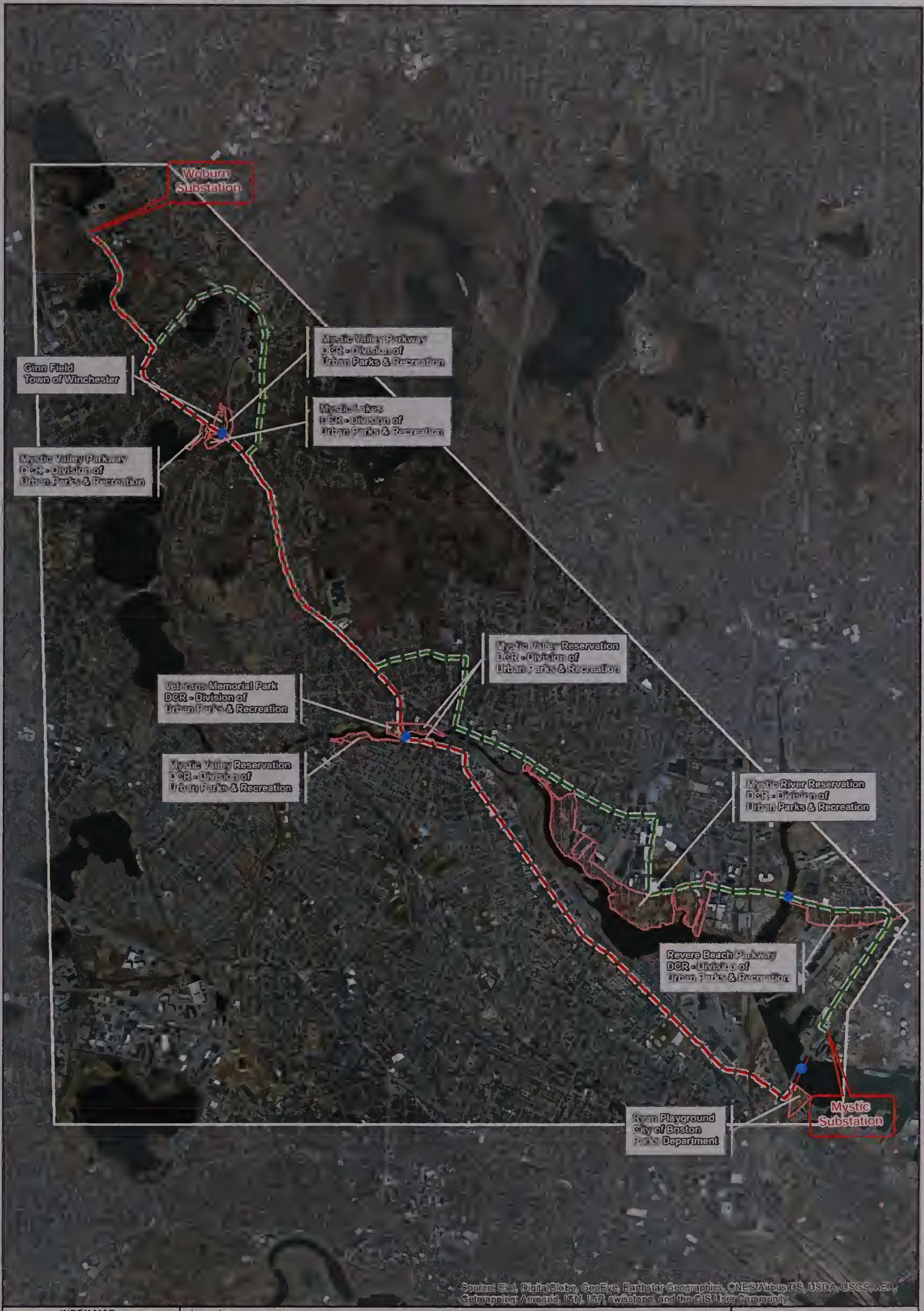
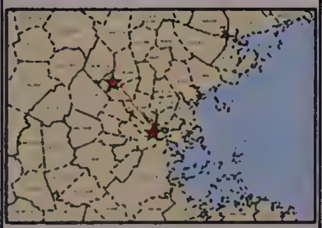

Woburn Substation
Ginn Field
Town of Winchester
Mystic Valley Parkway
DCR - Division of
Urban Parks & Recreation
Mystic Lakes
DCR - Division of
Urban Parks & Recreation
Mystic Valley Parkway
DCR - Division of
Urban Parks & Recreation
Mystic Valley Reservation
DCR - Division of
Urban Parks & Recreation
Veterans Memorial Park
DCR - Division of
Urban Parks & Recreation
Mystic Valley Reservation
DCR - Division of
Urban Parks & Recreation
Mystic River Reservation
DCR - Division of
Urban Parks & Recreation
Revere Beach Parkway
DCR - Division of
Urban Parks & Recreation
Ryan Playground
City of Boston
Parks Department
Mystic Substation

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

INDEX MAP



Map Notes:
Basemap: USGS Quadrangle Basemap, MassGIS

Legend

- ● Waterbody Crossing
- Preferred Route
- Noticed Alternative Route
- Existing Mystic River Crossing
- ▭ Article 97 Lands

Mystic to Woburn
Transmission Project

Figure 7

Article 97 Lands

0 1,000 2,000 4,000
Feet

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ENERGY

POWER
Environmental Services Div

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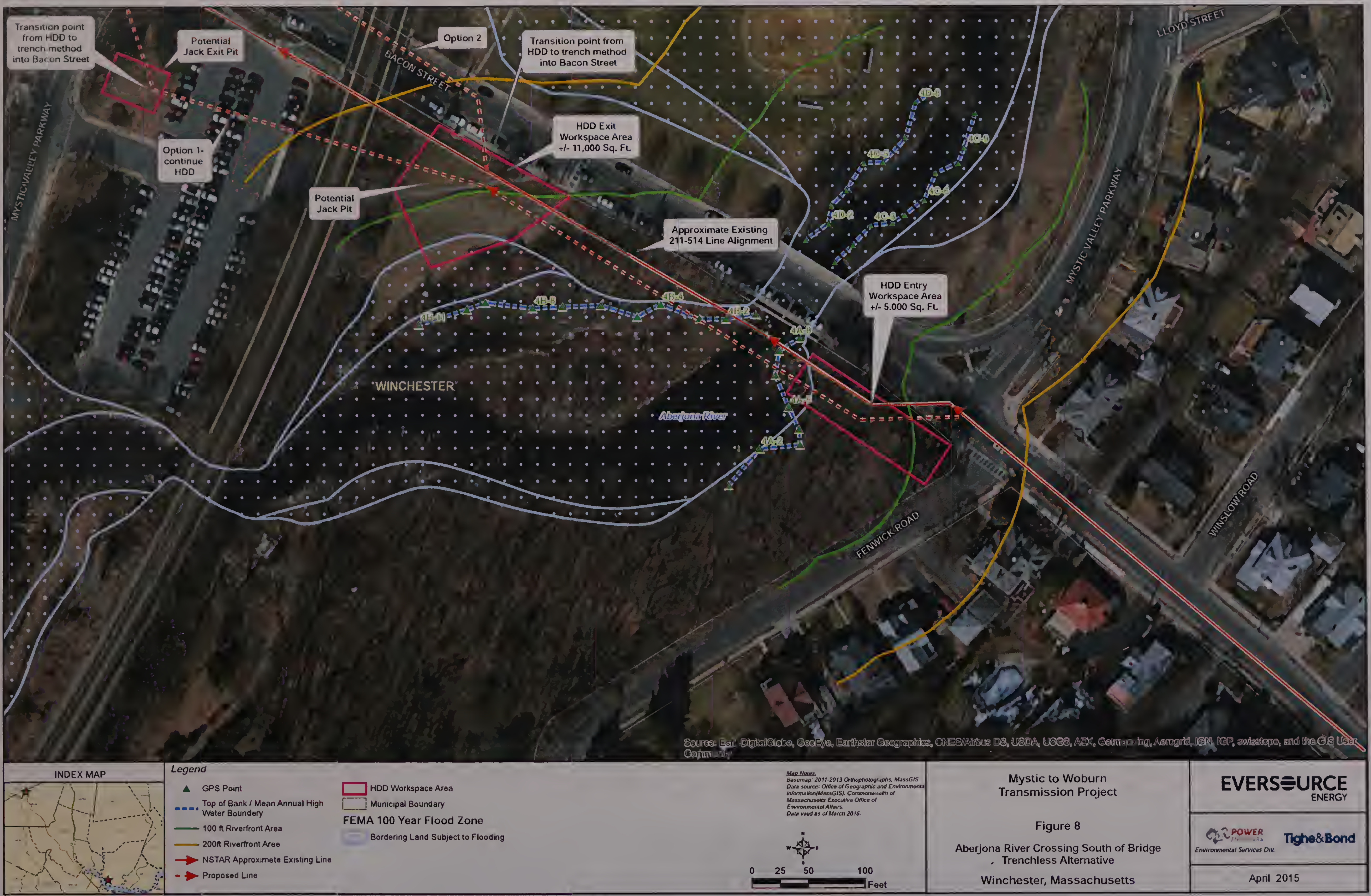
April 2015

S:\GIS\MA\EversourceEnergy\N0996\Mystic_To_Woburn_Line211-514\MapDocuments\MEPA_ENF\Fig7_Article 97 Lands.mxd



Transition point from HDD to trench method into Bacon Street
Potential Jack Exit Pit
Option 2
Transition point from HDD to trench method into Bacon Street
BACON STREET
LLOYD STREET
Option 1- continue HDD
HDD Exit Workspace Area +/- 11,000 Sq. Ft.
Potential Jack Pit
Approximate Existing 211-514 Line Alignment
HDD Entry Workspace Area +/- 5,000 Sq. Ft.
MYSTIC VALLEY PARKWAY
MYSTIC VALLEY PARKWAY
FENWICK ROAD
WINSLOW ROAD
WINCHESTER
Aberjona River
4D-8
4D-5
4D-4
4D-3
4D-2
4B-8
4B-4
4B-2
4A-8
4A-2
Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
INDEX MAP
Legend
GPS Point
Top of Bank / Mean Annual High Water Boundery
100 ft Riverfront Area
200ft Riverfront Aree
NSTAR Approximete Existing Line
Proposed Line
HDD Workspace Area
Municipal Boundary
FEMA 100 Year Flood Zone
Bordering Land Subject to Flooding
N
0 25 50 100 Feet

Map Notes.
Basemap: 2011-2013 Orthophotographs, MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS). Commonwealth of Massachusetts Executive Office of Environmental Affairs.
Data valid as of March 2015.

Mystic to Woburn
Transmission Project

Figure 8

Aberjona River Crossing South of Bridge
, Trenchless Alternative

Winchester, Massachusetts

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POWER
Environmental Services Div.

Tighe&Bond

April 2015

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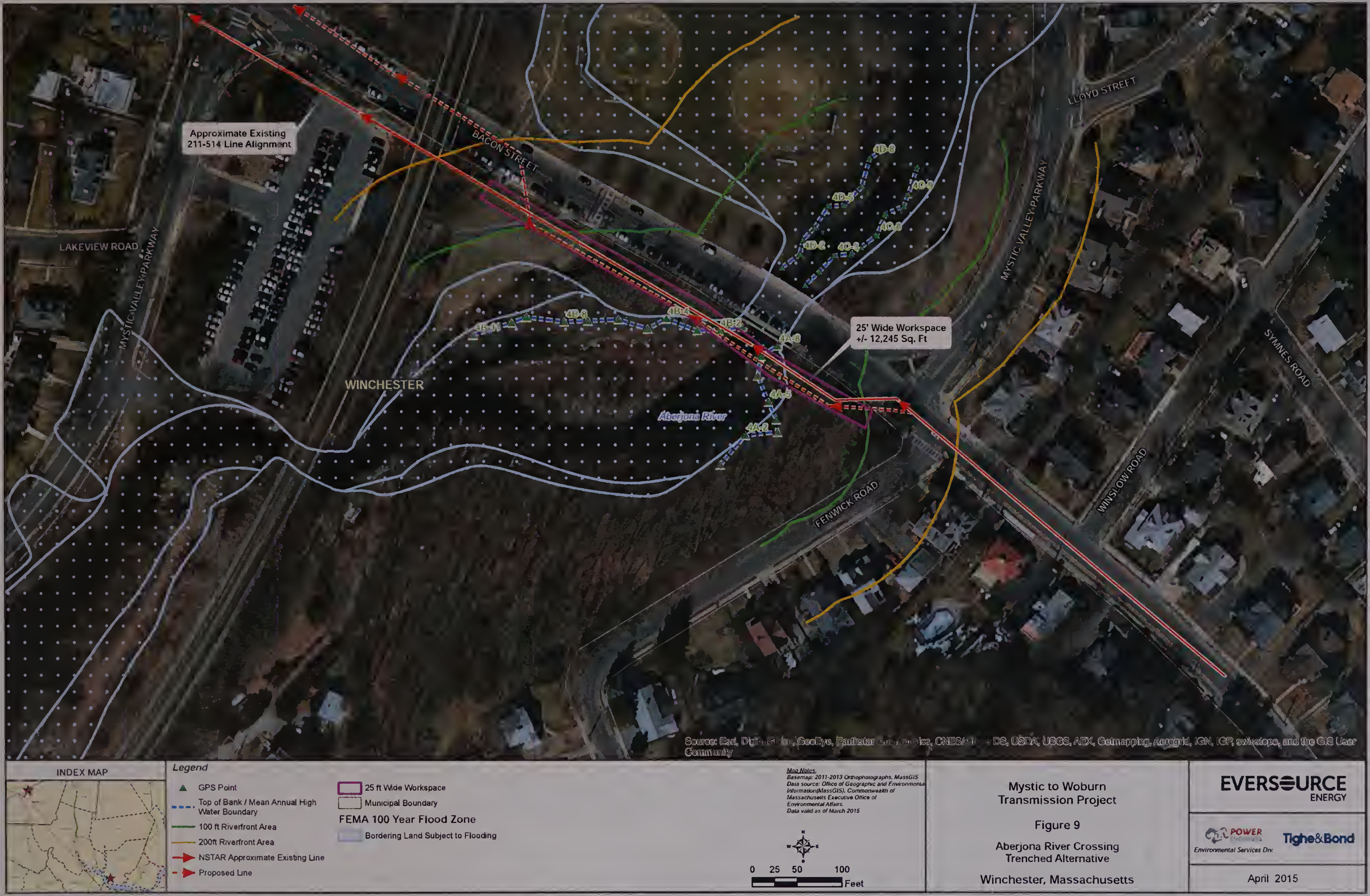
Approximate Existing
211-514 Line Alignment
BACON STREET
LLOYD STREET
MYSTIC VALLEY PARKWAY
LAKEVIEW ROAD
MYSTIC VALLEY PARKWAY
4D-8
4D-9
4D-5
4D-6
4D-2
4D-3
4B-8
4B-4
4B-2
4B-11
4A-8
4A-5
4A-2
25' Wide Workspace
+/- 12,245 Sq. Ft
SYMNES ROAD
WINCHESTER
Aberjona River
FENWICK ROAD
WINSLOW ROAD
INDEX MAP
Legend
▲ GPS Point
Top of Bank / Mean Annual High Water Boundary
100 ft Riverfront Area
200ft Riverfront Area
NSTAR Approximate Existing Line
Proposed Line
25 ft Wide Workspace
Municipal Boundary
FEMA 100 Year Flood Zone
Bordering Land Subject to Flooding
N
W
E
S
0
25
50
100
Feet

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

Map Notes.
Basemap: 2011-2013 Orthophotographs, MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS), Commonwealth of Massachusetts Executive Office of Environmental Affairs.
Data valid as of March 2015

Mystic to Woburn
Transmission Project

Figure 9

Aberjona River Crossing
Trenched Alternative

Winchester, Massachusetts

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April 2015

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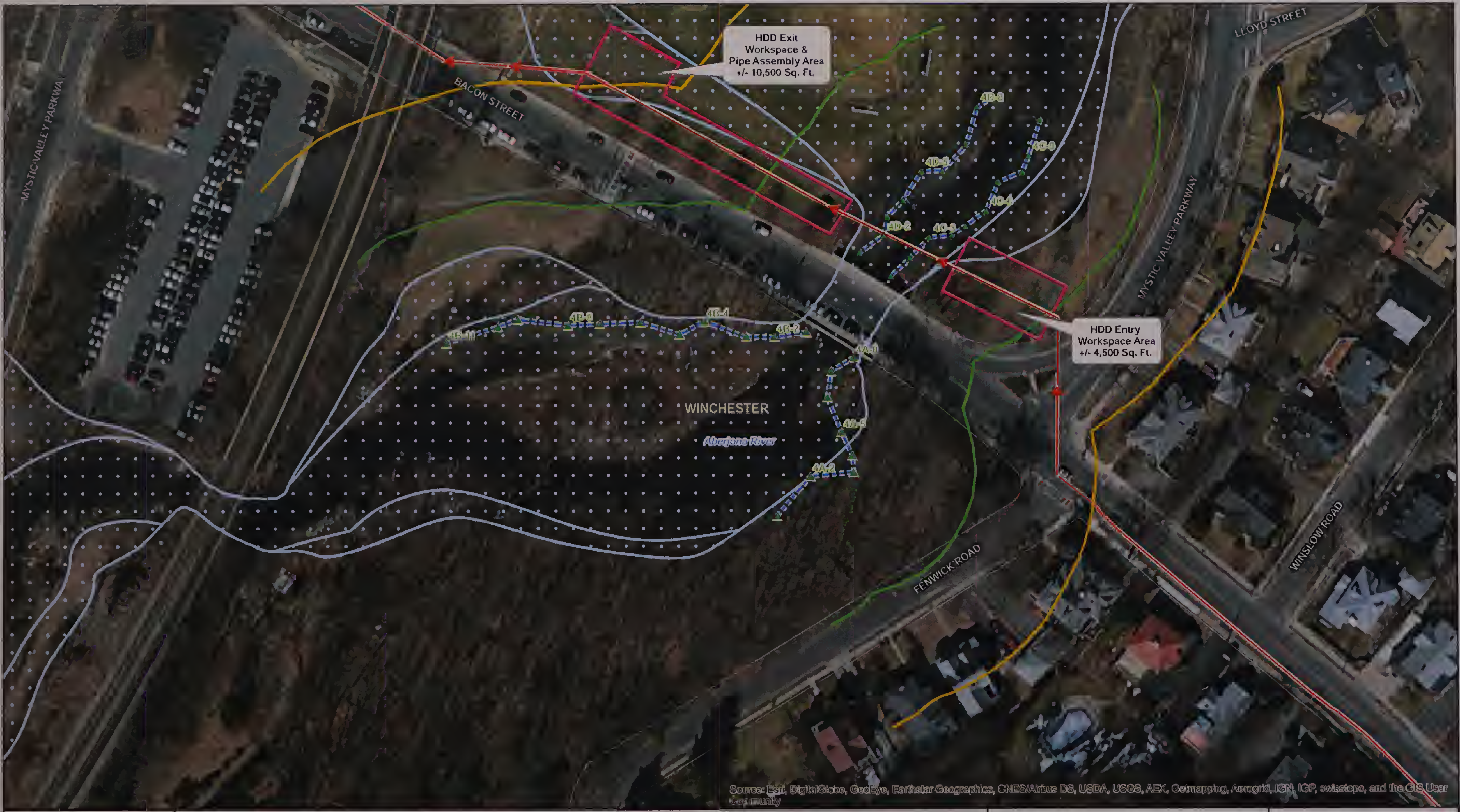
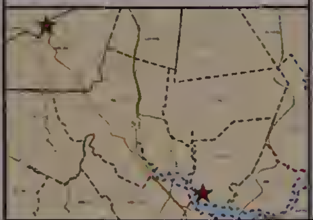

LLOYD STREET
MYSTIC VALLEY PARKWAY
WINSLOW ROAD
FENWICK ROAD
BACON STREET
MYSTIC VALLEY PARKWA
WINCHESTER
Aberjona River
4D-8
4C-3
4D-3
4C-4
4D-2
4C-2
4B-3
4B-4
4B-2
4B-1
4A-1
4A-3
4A-2

HDD Exit Workspace & Pipe Assembly Area +/- 10,500 Sq. Ft.

HDD Entry Workspace Area +/- 4,500 Sq. Ft.

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

INDEX MAP



Legend

- ▲ GPS Point
- Top of Bank / Mean Annual High Water Boundary
- 100 ft Riverfront Area
- 200ft Riverfront Area
- Proposed Line
- 🟥 HDD Workspace Area
- ☐ Municipal Boundary

FEMA 100 Year Flood Zone

- ▨ Bordering Land Subject to Flooding

Map Notes:
Basemap: 2011-2013 Orthophotographs. MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS), Commonwealth of Massachusetts Executive Office of Environmental Affairs.
Data valid as of March 2015

0 25 50 100 Feet

Mystic to Woburn
Transmission Project

Figure 10

Aberjona River Crossing North of Bridge
, Trenchless Alternative

Winchester, Massachusetts

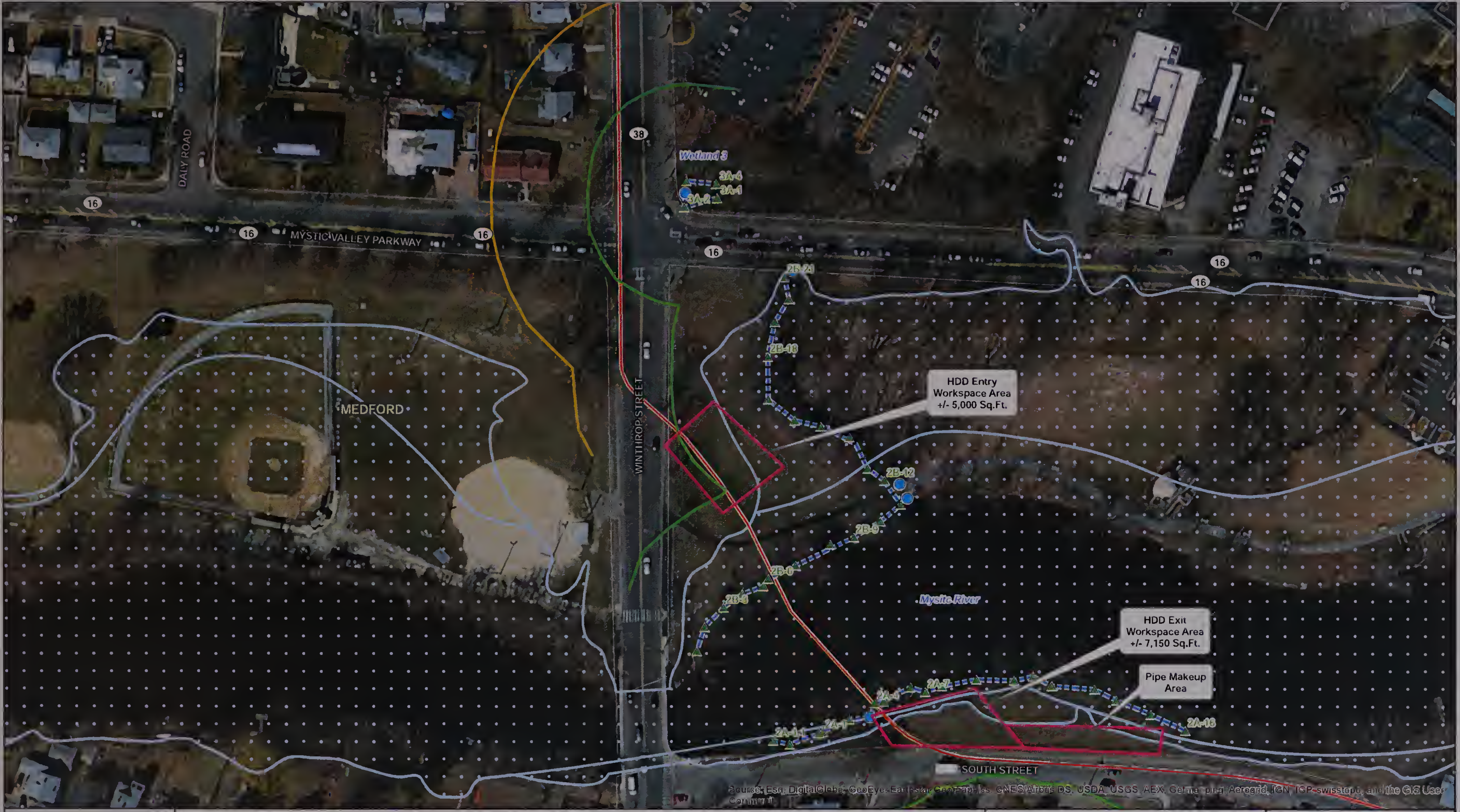
EVERSOURCE ENERGY

POWER Environmental Services Div

Tighe&Bond

April 2015

G:\GIS\MA\EversourceEnergy\N0998\Mystic_To_Woburn_Line211-514\MapDocuments\MEPA_ENF\Fig10_AberjonaTrenchless_North.mxd



Wetland 3
3A-4
3A-1
3A-2
38
16
DAILY ROAD
MYSTIC VALLEY PARKWAY
MEDFORD
WINTHROP STREET
2B-21
2B-18
2B-12
2B-9
2B-6
2B-3
Mystic River
HDD Entry Workspace Area +/- 5,000 Sq.Ft.
HDD Exit Workspace Area +/- 7,150 Sq.Ft.
Pipe Makeup Area
2A-4
2A-7
2A-1
2A-1-1
2A-16
SOUTH STREET

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community

INDEX MAP

Legend

▲	GPS Point
●	Culvert
- - -	Top of Bank / Mean Annual High Water Boundary
—	100 ft Riverfront Area
—	200 ft Riverfront Area
—	Proposed Line
▭	HDD Workspace Area
▭	Municipal Boundary

FEMA 100 Year Flood Zone

▨	Bordering Land Subject to Flooding

Map Notes:
Basemap: 2011-2013 Orthophotographs, MassGIS
Data source: Office of Geographic and Environmental Information(MassGIS), Commonwealth of Massachusetts Executive Office of Environmental Affairs.
Date valid as of March 2015

0 25 50 100 Feet

Mystic to Woburn
Transmission Project

Figure 11

Mystic River Crossing
Trenchless Alternative

Medford, Massachusetts

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April 2015

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Attachment C
Distribution List

In accordance with Section 11.16 of the MEPA regulations (301 CMR 11.00), this ENF has been distributed to the following federal, state, and local agencies/departments for review.

State Agencies

Secretary Matthew A. Beaton (2 copies submitted herein)
Executive Office of Energy and Environmental Affairs
Attn: MEPA Office
100 Cambridge Street, Suite 900
Boston, MA 02114

Department of Environmental Protection
Commissioner's Office
One Winter Street
Boston, MA 02108

DEP/Northeast Regional Office
Attn: MEPA Coordinator
205B Lowell Street
Wilmington, MA 01887

MassDOT Public/Private Development Unit
10 Park Plaza
Boston, MA 02116

MassDOT District #4
Attn: MEPA Coordinator
519 Appleton Street
Arlington, MA 02476

MassDOT District #6
Attn: MEPA Coordinator
185 Kneeland Street
Boston, MA 02111

Massachusetts Historical Commission
The MA Archives Building
220 Morrissey Boulevard
Boston, MA 02125

Metropolitan Area Planning Council
60 Temple Place/6th floor
Boston, MA 02111

Coastal Zone Management
Attn: Project Review Coordinator
251 Causeway Street, Suite 800
Boston, MA 02114

Division of Marine Fisheries (North Shore)
Attn: Environmental Reviewer
30 Emerson Avenue
Gloucester, MA 01930
Email: DMF.EnvReview-North@state.ma.us

Department of Agricultural Resources
Attn: MEPA Coordinator
16 West Experiment Station
University of Massachusetts
Amherst, MA 01003

Natural Heritage and Endangered Species Program
Massachusetts Division of Fisheries & Wildlife
100 Hartwell St, Suite 230
West Boylston, MA 01581

DCR
Attn: MEPA Coordinator
251 Causeway St. Suite 600
Boston MA 02114

Department of Public Health (DPH)
Director of Environmental Health
250 Washington Street
Boston, MA 02115

Energy Facilities Siting Board
Attn: MEPA Coordinator
One South Station
Boston, MA 02110

Department of Energy Resources
Attn: MEPA Coordinator
100 Cambridge Street, 10th floor
Boston, MA 02114

Massachusetts Water Resource Authority
Attn: MEPA Coordinator
100 First Avenue
Charlestown Navy Yard
Boston, MA 02129

Massachusetts Bay Transit Authority
Attn: MEPA Coordinator
10 Park Plaza, 6th Fl.
Boston, MA 02116-3966

Department of Public Utilities
One South Station
Boston, MA 02110

City of Woburn

Woburn City Council
Office of the City Clerk
City Hall
10 Common Street
Woburn, MA 01801

Woburn Planning Board
City Hall
10 Common Street
Woburn, MA 01801

Woburn Conservation Commission
City Hall
10 Common Street
Woburn, MA 01801

Woburn Board of Health
City Hall
10 Common Street
Woburn, MA 01801

Town of Winchester

Winchester Board of Selectmen
Town Hall
71 Mt. Vernon St.
2nd Floor
Winchester, MA 01890

Winchester Planning Board
Town Hall
71 Mt. Vernon St.
Lower Level
Winchester, MA 01890

Winchester Conservation Commission
Town Hall
71 Mt. Vernon St.
Winchester, MA 01890

Winchester Board of Health
Town Hall
71 Mt. Vernon St.
Lower Level
Winchester, MA 01890

City of Medford

Medford City Council
City Hall
85 George P. Hassett Drive
Room 207
Medford, MA 02155

Medford Community Development
City Hall
85 George Hassett Drive
Room 308
Medford, MA 02155

Medford Conservation Commission
City Hall
85 George P. Hassett Drive
Room 205
Medford, MA 02155

Medford Board of Health
City Hall
85 George P. Hassett Drive
Room 311
Medford, MA 02155

City of Somerville

Somerville Board of Aldermen
City Hall - Aldermanic Chamber
93 Highland Avenue
Somerville, MA 02143

Somerville Planning Board
City Hall
93 Highland Avenue
Somerville, MA 02143

Somerville Conservation Commission
City Hall
93 Highland Avenue
Somerville, MA 02143

Somerville Board of Health
City Hall Annex
50 Evergreen Avenue
Somerville, MA 02145

City of Everett

Everett City Council
City Hall
484 Broadway
Room 38
Everett, MA 02149

Everett Department of Planning and Development
City Hall, Room 25
484 Broadway
Everett, MA 02149

Everett Conservation Commission
City Hall
484 Broadway
Everett, MA 02149

Everett Board of Health
City Hall, Room 20
484 Broadway
Everett, MA 02149

City of Boston

Boston City Council
1 City Hall Square, Suite 550
Boston, MA 02201-2043

Boston Redevelopment Authority
1 City Hall, Ninth Floor
Boston, Massachusetts 02201

Boston Conservation Commission
1 City Hall Square
Room 709
Boston, MA 02201

Boston Public Health Commission
1010 Massachusetts Avenue
Boston, MA 02118

Attachment D
List of Permits and Approvals

The below table outlines the permits and approvals for the proposed Project as required by Federal, State and local agencies.

Agency	Permit/Approval
Federal	
U.S. Environmental Protection Agency	U.S. Clean Water Act - NPDES General Permit for Stormwater Discharge from Construction Activities
U.S. Army Corps of Engineers	Section 404 of the U.S. Clean Water Act/ Section 10 of the Rivers and Harbors Act
Commonwealth of Massachusetts	
Executive Office of Energy and Environmental Affairs ("EEA")	Massachusetts Environmental Policy Act (MEPA) (MGL C. 30, s 61-62H) Review Environmental Notification Form
Massachusetts Department of Environmental Protection ("MassDEP") Wetlands and Waterways	Massachusetts Clean Water Act (MGL C. 21, s 26-53) – Individual 401 Water Quality Certificate Massachusetts Public Water Front Act (MGL C. 91) – Waterways Request for Determination of Applicability Utility Related Abatement Measures (as needed following soil pre-characterization)
Massachusetts Natural Heritage and Endangered Species Program ("NHESP")	Review under the Massachusetts Endangered Species Act (MGL C. 131A) & Project Review Checklist
Massachusetts Department of Public Utilities	MGL C. 164, s. 72 – Petition to Construct MGL C. 40A, s. 3 - Zoning Exemption
Massachusetts Historical Commission	State Register Review
Massachusetts Department of Transportation ("MassDOT")	Highway Access Permit
Department of Conservation and Recreation ("DCR")	Construction and Access Permit Article 97 for Long Term Easement
Massachusetts Bay Transit Authority ("MBTA")	Access Permit
Massachusetts Water Resources Authority ("MWRA")	Section 8(m) Permit of Chapter 372 of the Acts of 1984
Town of Winchester, Massachusetts	
Conservation Commission	Massachusetts Wetlands Protection Act (MGL C 131, s 40)/Local Wetlands Bylaw – Order of Conditions / Certificate of Compliance
Board of Selectmen	Grant of Location
City of Medford, Massachusetts	
Conservation Commission	Massachusetts Wetlands Protection Act (MGL C 131, s 40)/Local Wetlands Ordinance – Order of Conditions / Certificate of Compliance
City Council	Grant of Location
City of Somerville, Massachusetts	
Conservation Commission	Massachusetts Wetlands Protection Act (MGL C 131, s 40)/Local Wetlands Ordinance– Determination of Applicability

Board of Aldermen	Grant of Location
City of Everett, Massachusetts	
Conservation Commission	Massachusetts Wetlands Protection Act (MGL C 131, s 40)/Local Wetlands Ordinance– Determination of Applicability
City Council	Grant of Location
City of Boston, Massachusetts	
Conservation Commission	Massachusetts Wetlands Protection Act (MGL C 131, s 40)/Local Wetlands Ordinance– Determination of Applicability
Public Improvement Commission	Grant of Location
Winchester, Medford, Boston, Somerville, and Everett	
Public Works	Street Opening Permits and Traffic Management Plans
Police Department	Police Detail / Traffic Management Plans

Attachment E
Excerpts from Massachusetts 2012 Integrated List of Waters

Massachusetts Year 2012 Integrated List of Waters

Final Listing of the Condition of Massachusetts' Waters Pursuant to Sections 305(b), 314 and 303(d) of the Clean Water Act

Featuring new water quality assessments for the Blackstone, Boston Harbor (including Mystic, Neponset and Weymouth/Weir), Merrimack and Parker watersheds and the Cape Cod coastal drainage areas

Commonwealth of Massachusetts
Executive Office of Energy and Environmental Affairs
Richard K. Sullivan, Jr., Secretary
Massachusetts Department of Environmental Protection
Kenneth L. Kimmell, Commissioner
Bureau of Resource Protection
Bethany A. Card, Assistant Commissioner

Massachusetts Category 3 Waters
"No uses assessed"

NAME	SEGMENT ID	DESCRIPTION	SIZE	UNITS
Sportsmans Pond	MA35082	Athol	92.724	ACRES
Sunset Lake	MA35086	Ashburnham/Winchendon	274.257	ACRES
Tully Lake	MA35111	Royalston/Athol	213.679	ACRES
Tully Pond	MA35089	Orange	70.152	ACRES
Wallace Pond	MA35092	Ashburnham	46.086	ACRES
Ward Pond	MA35093	Athol	5.899	ACRES
Wheelers Pond	MA35097	Warwick	28.286	ACRES
Wickett Pond	MA35102	Wendell	29.931	ACRES
Wrights Reservoir	MA35104	Gardner/Westminster	130.848	ACRES
Mount Hope Bay				
Cook Pond	MA61001	Fall River, MA/Tiverton, RI	157	ACRES
South Watuppa Pond	MA61006	Fall River/Westport	1473	ACRES
Mystic				
Bellevue Pond	MA71004	Medford	2	ACRES
Cummings Brook	MA71-10	Headwaters east of Wright Street, Wobum to confluence with Fowle Brook, Woburn.	2.1	MILES
Sales Crrek	MA71-12	Headwaters near Route 145, Revere to tidegate/confluence with Belle Isle Inlet, Boston/Revere.	0.008	SQUARE MILES
Shaker Glen Brook	MA71-11	Headwaters, west of Dix Road Extention, Woburn to confluence with Fowle Brook, Woburn (portion culverted underground).	1.5	MILES
Spot Pond	MA71039	Stoneham/Medford	290	ACRES
Narragansett Bay				
Bad Luck Brook	MA53-11	Headwaters, outlet Warren Upper Reservoir, Rehoboth to confluence with East Branch Palmer River, Rehoboth	1.7	MILES
Beaverdam Brook	MA53-10	Headwaters, southeast of Chestnut Street, Rehoboth to confluence with Palmer River, Rehoboth	2.9	MILES
East Branch Palmer River	MA53-08	Headwaters, near Stevens Corner Cemetery, Rehoboth to confluence with West Branch Palmer River (forming Palmer River), Rehoboth	7.2	MILES
Fullers Brook	MA53-12	Headwaters in wetland north of Jacobs Street, Seekonk to confluence with Palmer River, Rehoboth	1.7	MILES
Oak Swamp Brook	MA53-15	Headwaters in Oak Swamp east of School Street, Rehoboth to confluence with Rocky Run, Rehoboth	3	MILES
Rumney Marsh Brook	MA53-09	Headwaters, east of Locust Avenue, Rehoboth to confluence with Beaverdam Brook, Rehoboth	1.3	MILES
Torrey Creek	MA53-14	Headwaters in wetland east of Benson Avenue, Seekonk to Barney Avenue, Rehoboth (includes culverted section near Seekonk Speedway, Seekonk)	2.1	MILES
West Branch Palmer River	MA53-07	From confluence of Bliss Brook, Rehoboth to confluence with East Branch Palmer River (forming Palmer River), Rehoboth	3.8	MILES
Nashua				
Ashby Reservoir	MA81001	Ashby	36	ACRES
Asnebumskit Pond	MA81002	Paxton	43	ACRES

Massachusetts Category 5 Waters
"Waters requiring a TMDL"

NAME	SEGMENT ID	DESCRIPTION	SIZE	UNITS	IMPAIRMENT CAUSE	EPA TMDL NO.
Lee River	MA61-01	From confluence with Lewin Brook, Swansea to Route 6, Swansea/Somerset	0.02	SQUARE MILES	Fecal Coliform	38905
					Nutrient/Eutrophication Biological Indicators	
Lee River	MA61-02	Route 6, Swansea/Somerset to mouth at Mount Hope Bay, Swansea/Somerset	0.51	SQUARE MILES	(Debris/Floatables/Trash*)	
					Chlorophyll-a	
					Fecal Coliform	38906
					Nitrogen (Total)	
					Oxygen, Dissolved	
					Taste and Odor	
Mount Hope Bay	MA61-06	the Massachusetts portion from the Braga Bridge, Fall River/Somerset to the state border Fall River, MA/Tiverton, RI to the line from Braton Point Somerset to MA/RI border approximately 3/4 of a mile due east of Spar Island, RI	2.29	SQUARE MILES	Chlorophyll-a	
					Fecal Coliform	38908
					Fishes Bioassessments	
					Nitrogen (Total)	
					Temperature, water	
Mount Hope Bay	MA61-07	the Massachusetts portion from mouth of Cole River (at old railway grade), Swansea to state border Swansea, MA/Warren, RI to the line from Brayton Point, Somerset to MA/RI border approximately 3/4 of a mile due east of Spar Island, RI to the line between Bay Point, Swansea and Brayton Point, Somerset (the mouth of the Lee River)	1.84	SQUARE MILES	Chlorophyll-a	
					Fecal Coliform	38909
					Fishes Bioassessments	
					Nitrogen (Total)	
					Oxygen, Dissolved	
					Temperature, water	
Mystic						
Aberjona River	MA71-01	Source just south of Birch Meadow Drive, Reading to inlet Upper Mystic Lake at Mystic Valley Parkway, Winchester (portion culverted underground). (through former pond segments Judkins Pond MA71021 and Mill Pond MA71031).	9.1	MILES	(Physical substrate habitat alterations*)	
					Ammonia (Un-ionized)	
					Aquatic Macroinvertebrate Bioassessments	
					Arsenic	
					Escherichia coli	
					Oxygen, Dissolved	
					Phosphorus (Total)	
					Sediment Bioassays -- Chronic Toxicity Freshwater	
					Turbidity	

* TMDL not required (Non-pollutant)

Massachusetts Category 5 Waters
"Waters requiring a TMDL"

NAME	SEGMENT ID	DESCRIPTION	SIZE	UNITS	IMPAIRMENT CAUSE	EPA TMDL NO.
Hom Pond	MA71019	Woburn	108	ACRES	(Non-Native Aquatic Plants*)	
					Excess Algal Growth	
					Oxygen, Dissolved	
					Phosphorus (Total)	
Lower Mystic Lake	MA71027	Arlington/Medford	93	ACRES	DDT	
					Oxygen, Dissolved	
					PCB in Fish Tissue	
					Salinity	
					Sediment Bioassays -- Chronic Toxicity Freshwater	
					Sulfide-Hydrogen Sulfide	
Malden River	MA71-05	Headwaters south of Exchange Street, Malden to confluence with Mystic River, Everett/Medford.	2.3	MILES	(Debris/Floatables/Trash*)	
					Chlordane	
					DDT	
					Dissolved oxygen saturation	
					Escherichia coli	
					Fecal Coliform	
					Foam/Flocs/Scum/Oil Slicks	
					Oxygen, Dissolved	
					PCB in Fish Tissue	
					pH, High	
					Phosphorus (Total)	
					Secchi disk transparency	
					Sediment Bioassays -- Chronic Toxicity Freshwater	
					Taste and Odor	
					Total Suspended Solids (TSS)	
Mill Brook	MA71-07	Headwaters south of Massachusetts Avenue, Lexington to inlet of Lower Mystic Lake, Arlington (portions culverted underground).	3.9	MILES	(Physical substrate habitat alterations*)	
					Escherichia coli	
Mill Creek	MA71-08	From Route 1, Chelsea/Revere to confluence with Chelsea River, Chelsea/Revere.	0.02	SQUARE MILES	Fecal Coliform	
					Other	
					PCB in Fish Tissue	

* TMDL not required (Non-pollutant)

Massachusetts Category 5 Waters
"Waters requiring a TMDL"

NAME	SEGMENT ID	DESCRIPTION	SIZE	UNITS	IMPAIRMENT CAUSE	EPA TMDL NO.
Mystic River	MA71-02	Outlet Lower Mystic Lake, Arlington/Medford to Amelia Earhart Dam, Somerville/Everett.	4.9	MILES	(Fish-Passage Barrier*)	
					Arsenic	
					Chlordane	
					Chlorophyll-a	
					DDT	
					Dissolved oxygen saturation	
					Escherichia coli	
					PCB in Fish Tissue	
					Phosphorus (Total)	
					Secchi disk transparency	
					Sediment Bioassays -- Chronic Toxicity Freshwater	
Mystic River	MA71-03	Amelia Earhart Dam, Somerville/Everett to confluence with Boston Inner Harbor, Chelsea/Charlestown (Includes Island End River).	0.49	SQUARE MILES	Sediment Screening Value (Exceedence)	
					Ammonia (Un-ionized)	
					Fecal Coliform	
					Foam/Flocs/Scum/Oil Slicks	
					Other	
					Oxygen, Dissolved	
					PCB in Fish Tissue	
					Petroleum Hydrocarbons	
					Taste and Odor	
Spy Pond	MA71040	Arlington	98	ACRES	(Eurasian Water Milfoil, Myriophyllum spicatum*)	
					Chlordane	
					DDT	
					Excess Algal Growth	
					Oxygen, Dissolved	
					Phosphorus (Total)	
Unnamed Tributary	MA71-13	Unnamed tributary locally known as 'Meetinghouse Brook', from emergence south of Route 16/east of Winthrop Street, Medford to confluence with the Mystic River, Medford. (brook not apparent on 1985 Boston North USGS quad - 2005 orthophotos used to delineate stream)	0.1	MILES	Escherichia coli	

* TMDL not required (Non-pollutant)

Massachusetts Category 5 Waters
"Waters requiring a TMDL"

NAME	SEGMENT ID	DESCRIPTION	SIZE	UNITS	IMPAIRMENT CAUSE	EPA TMDL NO.
Upper Mystic Lake	MA71043	Winchester/Arlington/Medford	176	ACRES	(Non-Native Aquatic Plants*)	
					Dissolved oxygen saturation	
					Oxygen, Dissolved	
Wedge Pond	MA71045	Winchester	23	ACRES	Oxygen, Dissolved	
					Phosphorus (Total)	
Winn Brook	MA71-09	Headwaters near Juniper Road and the Belmont Hill School, Belmont to confluence with Little Pond, Belmont (portions culverted underground).	1.4	MILES	(Physical substrate habitat alterations*)	
					Escherichia coli	
Winter Pond	MA71047	Winchester	18	ACRES	(Non-Native Aquatic Plants*)	
					Nutrient/Eutrophication Biological Indicators	
Narragansett Bay						
Palmer River	MA53-04	From confluence of East and West Branches of the Palmer River, Rehoboth to the Shad Factory Pond dam, Rehoboth	5.6	MILES	(Low flow alterations*)	
					Fecal Coliform	35086
					Nutrient/Eutrophication Biological Indicators	
Runnins River	MA53-01	Route 44, Seekonk to Mobile Dam, Seekonk, MA/East Providence, RI (through Burrs Pond formerly segment MA53001)	3.7	MILES	(Debris/Floatables/Trash*)	
					Aquatic Macroinvertebrate Bioassessments	
					Fecal Coliform	38903
					Mercury in Fish Tissue	33880
					Nutrient/Eutrophication Biological Indicators	
					Oil and Grease	
					Oxygen, Dissolved	
Nashua						
Asnebumskit Brook	MA81-56	From outlet Eagle Lake, Holden to the confluence with the Quinapoxet River, Holden.	2.9	MILES	Ambient Bioassays -- Chronic Aquatic Toxicity	
Bartlett Pond	MA81008	Lancaster	5	ACRES	Escherichia coli	
Fort Pond	MA81046	Lancaster	76	ACRES	Oxygen, Dissolved	
Gates Brook	MA81-24	Headwaters west of Prospect Street, West Boylston to inlet Wachusett Reservoir (Gates Cove), West Boylston.	3.4	MILES	Fecal Coliform	

* TMDL not required (Non-pollutant)

APPENDIX 2-1

Greater Boston Area Updated Transmission Needs Assessment

January 30, 2015

(CEII Redacted)

Appendix 2-1

Greater Boston Area Updated Transmission Needs Assessment

"This Appendix contains information that has been redacted for Critical Energy Infrastructure Information (CEII)."

ISO new england

Greater Boston Area Updated Transmission Needs Assessment

Contains Critical Energy Infrastructure Information
Do Not Release

January 30, 2015

THIS APPENDIX CONTAINS INFORMATION THAT HAS BEEN REDACTED FOR CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII).

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Section 1

Executive Summary

1.1 Objective

The objective of the study was to identify reliability-based transmission needs in the Greater Boston study area while considering the following:

- Future load growth
- Long-term system transfer needs
- A range of generation patterns
- Regional and local reliability issues
- All applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Corporation (NPCC) and ISO New England transmission planning reliability standards

The scope of the Needs Assessment performed for the Greater Boston area included evaluation of the reliability performance of the transmission system serving this area of New England for the 2018 and 2023 projected system conditions. The system was tested with all lines in and under N-1 and N-1-1 contingency conditions for a number of possible operating conditions with respect to related interface transfer levels and generating unit availability conditions. The study area defined as Greater Boston included the area known as Northeast Massachusetts – Boston load zone or NEMA/Boston load zone, as well as some parts of the surrounding areas west of Boston and parts of the areas south of Boston and a small area that is a part of the New Hampshire load zone. In broad terms the Greater Boston study area can be described as the communities north and east of Interstate 495 up to the New Hampshire Border, the city of Boston and some of the suburbs south of Boston. The study area encompasses the Boston RSP subarea with the addition of some load in the west and south outside of the Boston RSP subarea. To account for the load and to describe the study area, the term Boston RSP subarea is used in general throughout the report even though a small portion of the study area is outside of the Boston RSP Subarea.

As described in this report, the Needs Assessment identified certain areas of the system that failed to meet thermal, voltage and short-circuit criteria when subjected to testing in accordance with NERC, NPCC, ISO New England Inc. (ISO-NE), and Transmission Owner standards and criteria.[1]

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[1] In many instances this report refers to results as being “violations”. These instances are violations of the thermal, voltage and short-circuit criteria being used in the study.

This Needs Assessment was the first step in the study process defined in accordance with the Regional Planning Process as outlined in Attachment K to the ISO-NE Open Access Transmission Tariff (OATT)2. In accordance with Attachment K, a Solutions Study will be conducted to develop and analyze potential transmission solutions for the needs identified in this analysis.

A working group led by ISO-NE, and consisting of members from ISO-NE, Northeast Utilities (NU), and National Grid has been studying the Greater Boston area since 2008. The results of the 2008 Needs Assessment were documented in the 2010 report titled "Greater Boston Area Transmission Needs Assessment" in July 2010. This report will be referred to as the 2010 Greater Boston Needs Assessment. In March 2012 the solutions study for the set of needs identified in the 2010 Greater Boston Needs Assessment was completed and a preferred solution was developed. This solution will be referred to as the March 2012 preferred solution. At this time New Hampshire Transmission (NHT) requested that a submarine HVDC cable (Sealink) from Seabrook to Boston be considered as an alternative to the preferred solution proposed by the working group. Subsequently, the Sealink alternative was studied in parallel to the March 2012 preferred solution. In February 2013 Footprint combined cycle cleared the Forward Capacity Auction 7 and with the addition of 674 MW of new resources in the Greater Boston study area there was a need to update the 2010 Needs Assessment. Hence, the Greater Boston working group, including NHT, reassessed the Greater Boston area transmission system. As part of the Planning Advisory Committee (PAC) process, stakeholders, which include generator owners, suppliers, load serving entities, energy efficiency entities, state regulators, and transmission owners, also provided input throughout the study process.

1.2 Method and Criteria

The Needs Assessment was performed in accordance with NERC TPL-001-4[3] Transmission System Standards[4], Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directory # 1[5], "*Design and Operation of the Bulk Power System*", ISO New England Planning Procedure 3[6], "Reliability Standards for the New England Area Bulk Power Supply System," ISO New England Planning Procedure 5-3[7], "Guidelines for Conducting and Evaluating

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[2] http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf

[3] http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf

[4] NERC TPL-001-04 also requires an evaluation of the power system one year, five years, and ten years out. This study only evaluated five years and ten years out load levels and system configurations however a critical load level assessment was conducted that identified the year of need.

[5] https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20%20Clean%20April%2020%202012%20GJD.pdf

[6] http://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp03/pp3_final.pdf

[7] http://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp05_3/pp5_3_final.pdf

Proposed Plan Application Analyses", as well as the criteria found in Appendix E: Assessment Criteria – Steady State Thermal and Voltage Criteria of this report.

The results of the analysis provided in this report have been organized by subareas to facilitate geographic orientation of the information. A set of defined subareas was developed based on a review of the thermal and voltage violations. As a result the Greater Boston area results were grouped into eight subareas. A more detail explanation of the subareas can be found in section 5.1. The defined subareas include the following:

A. 345 kV and 115 kV Northern ties to Greater Boston
B. Waltham, Woburn and Lexington Area
C. Downtown Boston 115 kV cables
D. Sudbury, Marlboro and Northborough area
E. W. Medway, W. Walpole and Holbrook area
F. Boston, Golden Hills and Wakefield Junction area
G. 115 kV Lines North of Boston in Salem area and Near Tewksbury[8]
H. 115 kV Lines Near Tewksbury

1.3 Study Assumptions

A near-term (five-year) and longer-term (ten-year) planning horizon, as mandated by NERC, was used for this study based on the most recently available Capacity, Energy, Loads, and Transmission (CELT) report (2013) at the time the study was updated. This study was focused on the projected 2018 peak demand load levels for the five-year horizon and 2023 peak demand load levels for the ten-year horizon using the 2013 CELT forecast. The models reflected the following peak load conditions:

2018 System Load Level Tested:

- The summer peak 90/10 load level forecast of 32,615 MW for all of New England and 6,830 MW for Boston RSP subarea peak demands

2023 System Load Level Tested:

- The summer peak 90/10 load level forecast of 34,460 MW for all of New England and 7,210 MW for Boston RSP subarea peak demands

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[8] Sub-Area G (115 kV Lines North of Boston in Salem area and Near Tewksbury) was studied but, due to recent upgrades, which include the Salem Harbor retirement upgrades, and the addition of new resources this sub-area was found to no longer result in any reportable reliability issues.)

The previous Needs Assessment report for this region of the system was based on the 2008 ISO-NE system load forecast. Subsequent to this assessment a number of transmission system and resource changes occurred. Please see the "Changes in Study Assumptions" in section 3.5 for a review of the chronology of events that affected the prior study results. These events lead to the conclusion that re-assessment of the area was necessary. This report describes the results of the updated Needs Assessment while preserving useful information that was provided in the original study report.

For the two load levels tested, demand resources (DR) in the form of active DR and passive DR that cleared the Forward Capacity Market (FCM) and forecasted Energy Efficiency as a part of the 2014 CELT forecast was modeled as load reductions. The details for these load reductions are included in section 3.1.12.

The existing Boston Import limit is approximately 4,175 MW under N-1-1 conditions based on the 2013 Regional System Plan[9]. However, no fixed transfer level was assumed for the purpose of testing the area's reliability. Instead the Boston Import transfer levels were driven by the various generating unit unavailability scenarios and are therefore the result of the sum of peak demand in the area minus on-line generating resources.

A total of 37 peak load cases and a total of four light load cases were modeled and used in all the N-0, N-1 and N-1-1 contingency testing which represented a number of possible generation dispatch and availability conditions. Variations and/or combinations of study area resources (Mystic, Kendall, HQ Phase II HVDC, as well as the proposed Footprint units[10]) versus variations of SEMA/RI, western New England, and northern New England generation were included in the system models tested. These dispatch conditions were also combined with interface transfer level variations to create a comprehensive set of possible system conditions.

Light load testing was also performed to assess high voltage conditions for the Greater Boston area. The testing resulted in a number of potential high voltage violations under N-1 and N-1-1 contingency conditions. Testing was performed for minimum load level of 8,500 MW and a summer off peak load level of 10,500 MW. Based on the current practice of changing the no-load tap position each season of certain transformers in the Greater Boston area, light or off peak loads during summer months could also introduce a voltage violation concern.

The cases tested are categorized throughout the report as design cases and retirement sensitivity cases. Design cases include reasonably expected generation unavailability with various New England system transfer stresses. In addition to the design cases with two critical units out of service, this study also includes limited testing with one critical unit out of service, recognizing that one generator out of service in the Boston RSP sub-Area may potentially highlight different issues than when there is more than one generator out of service, partly due to generator status-dependent system switching. A criteria violation in a design case constitutes a need that must be addressed by a proposed solution to meet criteria at the load level studied. Additional retirement sensitivity cases have been performed in response to stakeholder concerns. The Solutions Study intended to address the problems and concerns identified in this Needs Assessment will consider both design and retirement sensitivity cases to determine both the robustness of the proposed solutions and to identify the incremental upgrades associated with the sensitivities.

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[9] http://www.iso-ne.com/static-assets/documents/trans/rsp/2013/rsp13_final.docx

[10] Footprint consists of two units at the Salem Harbor 115 kV substation. They will be referred to collectively as "Footprint" or individually as Salem Harbor 5 and Salem Harbor 6

Design Cases

- **One Critical Unit Out of Service Cases**
  These cases assumed either Mystic 8 (345 kV), Mystic 9 (115 kV), Kendall, or one Footprint unit out of service, while simultaneously modeling a range of stressed conditions on the interfaces adjacent to the Boston RSP subarea which included the North-South interface, SEMA/RI interface and the East-West interface.

- **Two Critical Units Out of Service Cases**
  Various combinations of Boston RSP subarea unit outages were studied. These included combinations of Mystic 7, 8 and 9 as well as Kendall and Footprint units out of service. These cases assumed unavailability of two critical units in the Boston RSP subarea out of service while simultaneously modeling a range of stressed conditions on the interfaces adjacent to the Boston RSP subarea which included the North-South interface, SEMA/RI interface and the East-West interface. The Boston Import transfer level was above the existing N-1-1 limit for many of these cases.

A criteria violation in a design case in either a one critical unit or two critical units out of service case constitutes a need that must be addressed by a proposed solution.

Generation Retirement Sensitivity Cases

Generation retirement sensitivity case testing was performed based on stakeholder concerns that the older generating units or stations in the Boston RSP subarea could potentially retire from service in the near future or be subject to extended shutdown. This testing was limited to the oldest unit, Mystic 7, retired. Steady-state test results varied as a function of the system conditions modeled. A number of post-contingency overloads and voltage violations were observed in all of the various cases modeled and in many cases only the severity of the violations changed. There were also a number of post-contingency overloads and voltage violations that were only associated with specific system conditions.

Study Assumption from Prior Greater Boston Needs Assessment Report

This updated Greater Boston Transmission Needs Assessment report includes a number of significant study assumptions that have been introduced since the Needs Assessment study for this area was first initiated in 2008. In general the study assumption changes include 1) updates to the system load forecast and demand resources for New England as well as the Boston RSP subarea; 2) changes in the available generating resources, including retirement of Salem 1-4 and the addition of Footprint (Salem 5 & 6); and 3) an update to the ratings and modeling assumption of certain underground cable systems in the Boston RSP subarea.

1.4 Specific Areas of Concern

1.4.1 Steady State Testing Results

The results of the analysis for all of the study work completed indicated that there were a number of design case thermal overloads and voltage violations for N-1 and N-1-1 conditions. There were no design case criteria violations for N-0 conditions.

The results of the steady-state testing varied as a function of the system conditions modeled. A number of post-contingency thermal overloads and voltage violations were observed in all of the various base cases modeled and in many cases only the severity of the violations changed. There were also a number of post-contingency thermal overloads and voltage violations that were only associated with specific system conditions.

1.4.2 Review of N-0 Testing

N-0 (also known as “all-lines-in”) conditions were reviewed for the cases modeled. The results indicate that under all tested dispatch and transfer level conditions N-0 overloads were not observed given operational adjustments of the Boston area phase shifters. Additionally, there were no N-0 high or low voltage criteria violations observed.

1.4.3 Review of N-1 Testing

N-1 testing was performed for all the system conditions described above. A number of post-contingency violations seen in simulations were determined to be correctable through operational adjustments. The Boston area phase shifters, bus tie-breakers, HVDC runback and generation runback options are under the supervision of system operators and operators have the ability to mitigate a number of the problems initially identified. The stated operator actions can only be used to resolve overloads that are Long time emergency (LTE) rating violations but not Short time emergency (STE) rating violations.

Overall, by2023, N-1 contingency overloads were observed for elements within the Greater Boston area across the 69 kV, 115 kV and 345 kV transmission facilities. Some overloads were correctable through system adjustments but many are problems that will need to be addressed through a proposed solution. Retirement sensitivity case contingency overloads were similar to the design case problems in terms of the elements that were found to have overloads but were, in general, more severe than the design case results.

Table 1-1 below provides a summary of the total number of elements by subarea that had thermal LTE or STE violations under N-1 contingency conditions. The values shown include all 69 kV, 115 kV, 230 kV and 345 kV elements in the study area.

Table 1-1
Count of Number of Elements with N-1 Thermal Violations

Subarea	2018		2023	
	LTE[11] Overloaded Elements	STE Overloaded Elements	LTE[11] Overloaded Elements	STE Overloaded Elements
A	1	1	1	1
B	5	1	6	2
C	16	0	18	0
D	2	2	3	2
E	4	4	5	5
F	0	0	1	0
H	0	0	1	0

The table above excludes contingency overloads for the Y-151 line and for the 326 line. Overloads on these lines are mitigated [redacted]. The remaining elements that overload under N-1 conditions occur under various Greater Boston area contingencies for a number of Boston RSP subarea dispatch conditions. This specific element overload information is summarized in Section 5.1 below with detailed information provided in Section 5.2.2.

There were a limited number of voltage violations under N-1 conditions. Subarea D – Sudbury, Marlboro and Northboro and Subarea F – Boston, Golden Hills, and Wakefield Junction, both had a limited number of buses with low voltage violations under 2018 and 2023 peak load conditions.

Additionally under light load testing conditions, Subarea B – Boston, Golden Hills and Wakefield Junction, Subarea C – Downtown Boston 115 kV Cables, Subarea D - Sudbury, Marlboro and

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[11] The count of elements that are overloaded beyond LTE ratings includes those elements that are also overloaded beyond STE ratings.

Northboro, and Subarea E - Holbrook and West Walpole all had a limited number of buses with high voltage violations under minimum load and/or off peak load conditions.

1.4.4 Review of N-1-1 Testing

Initial element-out-of-service (N-1-1) testing included all 115 kV, 230 kV and 345 kV transmission lines as well as 345 kV autotransformers in the Greater Boston area that are considered Bulk Electric System (BES) elements. These element-out-of-service conditions were tested against the full set of contingencies used in the N-1 tests. These were tested for design cases and for retirement sensitivity cases that modeled retirement of Mystic Unit 7. N-1-1 testing was performed using an analytical tool that re-dispatched generation outside the Boston RSP subarea, modeled runback of generation inside the Boston RSP subarea, adjusted Phase II HVDC output and adjusted phase shifter settings within the Boston area to avoid overloads.

Table 1-2 below provides a summary of the total number of elements by subarea that had thermal LTE or STE violations under N-1-1 contingency conditions. The values shown include all 69 kV, 115 kV, 230 kV and 345 kV elements in the study area.

Table 1-2
Count of Number of Elements with N-1-1 Thermal Violations

Subarea	2018		2023	
	LTE[11] Overloaded Elements	STE Overloaded Elements	LTE[11] Overloaded Elements	STE Overloaded Elements
A	11	7	13	10
B	12	6	13	8
C	35	1	36	1
D	25	21	24	22
E	15	9	23	14
F	8	4	9	4
H	9	6	14	8

The table above excludes contingency overloads for the Y-151 line and for the 326 lines. Overloads on these lines are mitigated [redacted] The remaining elements that overload under N-1-1 conditions occur under various Greater Boston area contingencies for a number of Boston RSP subarea dispatch conditions. This specific element overload information is summarized in Section 5.1 below with detailed information provided in Section 5.2.2 below.

Additionally, there were a set of N-1 or N-1-1 events that resulted in consequential load loss that approached or exceeded 300 MW of customer load. These are load pockets within the system that are served by two transmission lines and the loss of both lines disconnects the load from the system. The mitigation of the following load interruptions under 2023 peak load conditions were identified as needs in the Greater Boston area:

Table 1-3
2023 Consequential Load Loss for N-1-1 or N-1 Events

Load Pocket	Contingency	Consequential Load Loss
Norwood/Canton/South Randolph Load Pocket (N-1)	[redacted]	324 MW
Sudbury Load Pocket (N-1-1)	[redacted]	298 MW
Revere/Chelsea Load Pocket (N-1-1)	[redacted]	357 MW

1.4.5 Short Circuit Testing

The Greater Boston study area is known to have limited short circuit margin at multiple substations based on past studies. The limited short circuit margins have proven in the past to be a significant challenge to integrate new resources and represent a potential problem for the integration of additional transmission facilities into the area.

A short-circuit assessment was conducted for this study, the results indicated that two 115 kV stations in downtown Boston [redacted] had a total of 26 breakers that would be overdutied under 2018 system model conditions.

1.5 Statements of Need

The results of the assessment conducted of the Greater Boston area transmission performance against transmission reliability standards for the projected 2018 and 2023 system conditions in this study indicate that there are a significant number of thermal, voltage and short circuit violations across a number of subareas within the Greater Boston system. The Greater Boston area transmission system fails to meet the reliability criteria standards in several geographical subareas under the design case testing performed and measures should be developed to mitigate the problems identified. A determination of the year of need was established for each element that was found to be exposed to potential overloads under contingency conditions. Additionally the specific reliability violations for each element that could potentially be overloaded are summarized by study year and categorized as design or retirement sensitivity case violations in Section 5.1. The results of the year of need analysis can be found in Section 6.1 in Table 6-1 and Table 6-2.

The year of need assessment shown in Section 6.1 was based on evaluation of the year and load level that elements first fail to meet criteria under N-1 and under N-1-1 contingency conditions. This assessment found that 9 out of 14 elements failed to meet criteria under N-1 contingency conditions prior to 2013 and that 2 of the 14 elements had an initial year more than 5 years from 2013. Additionally, it was found that under N-1-1 contingency conditions 36 out of 48 elements failed to meet criteria prior to 2013 and that 2 of the 48 overloaded elements had an initial year more than 5 years from 2013.

Section 2
Introduction and Background Information

2.1 Study Objective

The objective of the study was to identify reliability-based transmission needs in the Greater Boston study area while considering the following:

- Future load growth
- Long-term system transfer needs
- A range of generation patterns
- Regional and local reliability issues
- All applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Corporation (NPCC) and ISO New England transmission planning reliability standards

2.2 Area(s) Studied

The study area included all or part of several load zones that are considered to be collectively called the Greater Boston area for the purposes of this analysis. They included the load zone areas known as Northeast Massachusetts – Boston load zone or NEMA/Boston load zone, as well as some parts of the surrounding areas west of Boston, some of the load area south of Boston included in the Southeast Massachusetts load zone or SEMA load zone, and parts of the load area north of Boston included in the New Hampshire load zone (See Figure 2-1 and Figure 2-2). In broad terms the Greater Boston study area can be described as the communities north and east of Interstate 495 up to the New Hampshire Border, the city of Boston and some of the suburbs south of Boston. Quantifying the needs for Greater Boston area beyond the Boston RSP subarea allows for a comprehensive assessment of the Boston RSP subarea needs and for the potential that solutions developed to solve surrounding area needs are coordinated and designed to remedy multiple Boston RSP subarea needs, if possible. This study also coordinated with other surrounding area studies, such as New Hampshire and SEMA-RI. However, for accounting load and to describe the study area in general the term Boston RSP subarea is used in general through the report even though a small portion of the study area is outside the Boston RSP subarea.

The Greater Boston area is served by 345 kV, 230 kV, 115 kV and 69 kV transmission elements and substations. Existing generating units in the Boston RSP subarea range in size from 10 MW to 682 MW. Based on summer qualified capacity for FCA 7, these resources include a total of 1,952 MW at Mystic Station, 200 MW at Kendall Station (taking into account the partial Non-price retirement for FCA 8) and approximately 390 MW from a number of smaller units (<50 MW) for a total generation of 2,542 MW. Additionally, newly proposed units that have cleared the Forward Capacity Auction located within the Boston RSP subarea (Salem Harbor 5 and

Salem Harbor 6) were included in the study. These units are proposed to be constructed at the existing Salem Harbor generating site. There are two proposed units each with a qualified capacity of 337 MW for a total generating qualified capacity of 674 MW[12] which was included in the resource mix for the Boson Import area. A list of the major units, units over 100 MW, serving the Greater Boston area that were included in the study is provided in Table 2-1 below. As discussed in Section 3.1.7, the peak load for the Boston RSP subarea in 2023 is projected to be 7,210 MW. In addition to the 3,216 MW of generation, there is 784 MW of active and passive demand resources available in the area through FCA-7 and additional forecasted EE for the years 2018-2023. The details of the DR modeled in the case are provided in Table 3-1.

Table 2-1
Major Greater Boston Area Generating Units (>100 MW)

Generating Units	Qualified Capacity[13]	Commercial Operation Year	Age (years)
Mystic 7	578	1975	39
Mystic 8	682	2003	11
Mystic 9	692	2003	11
Kendall CT	154	2002	12
Salem Harbor 5	337	2017[14]	N/A
Salem Harbor 6	337	2017[14]	N/A
TOTAL	**2780**		

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[12] Footprint Combined Cycle or Salem 5 and 6 obtained a Capacity Supply Obligation of 674 MW in FCA 7 which establishes the maximum qualified capacity for subsequent auctions.

[13] Net of station service.

[14] Expected in-service year

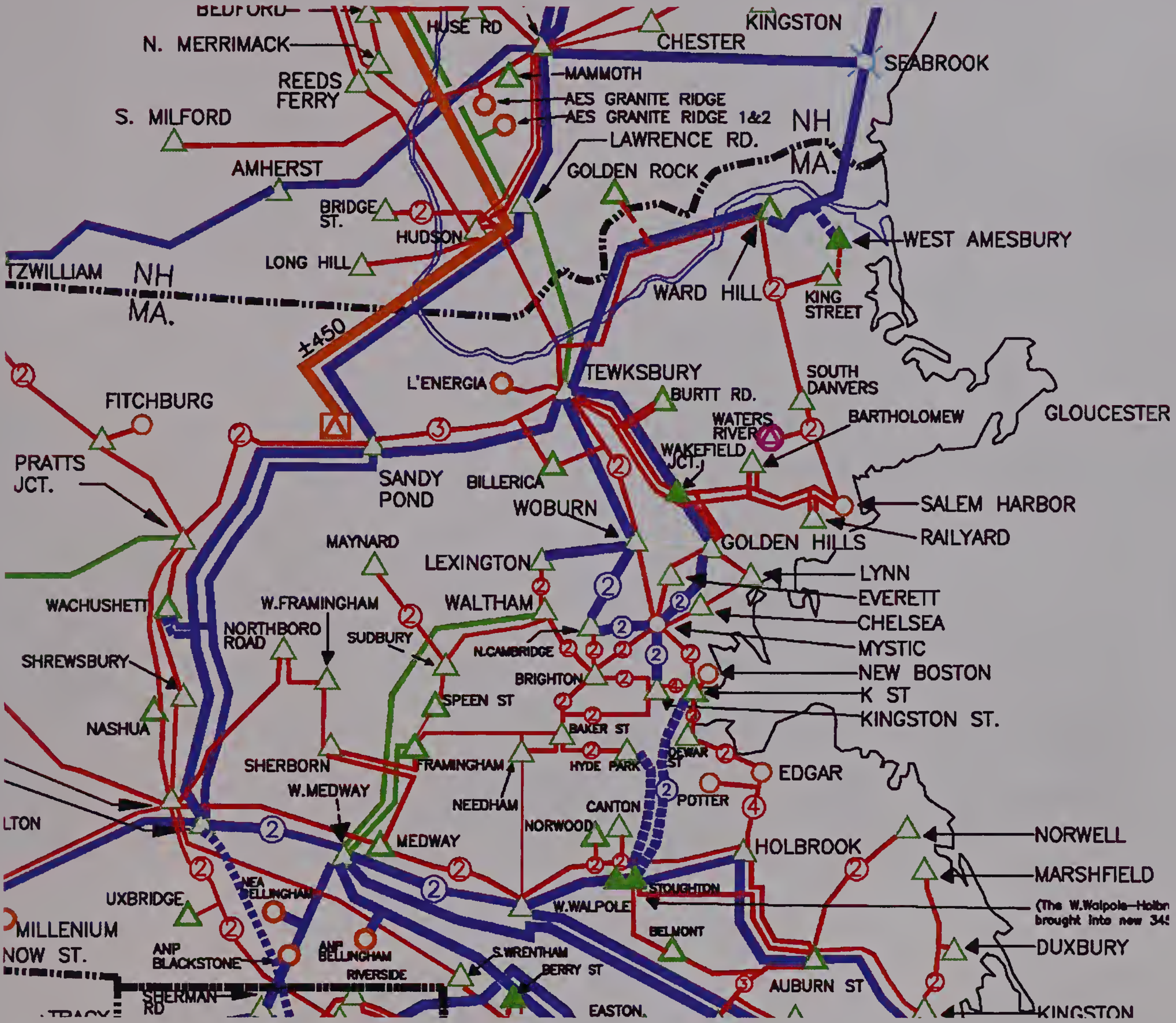
BEDFORD
N. MERRIMACK
HUSE RD
CHESTER
KINGSTON
SEABROOK
REEDS FERRY
MAMMOTH
AES GRANITE RIDGE
AES GRANITE RIDGE 1&2
S. MILFORD
LAWRENCE RD.
NH
MA.
AMHERST
GOLDEN ROCK
BRIDGE ST.
HUDSON
WEST AMESBURY
LONG HILL
TZWILLIAM
NH
MA.
WARD HILL
KING STREET
±450
TEWKSBURY
SOUTH DANVERS
L'ENERGIA
BURTT RD.
GLOUCESTER
FITCHBURG
WATERS RIVER
BARTHOLOMEW
WAKEFIELD JCT.
PRATTS JCT.
SANDY POND
BILLERICA
SALEM HARBOR
WOBURN
RAILYARD
MAYNARD
LEXINGTON
GOLDEN HILLS
LYNN
EVERETT
WACHUSHETT
W.FRAMINGHAM
WALTHAM
CHELSEA
NORTHBORO ROAD
SUDBURY
MYSTIC
N.CAMBRIDGE
SHREWSBURY
NEW BOSTON
BRIGHTON
K ST
SPEEN ST
KINGSTON ST.
NASHUA
BAKER ST
DEWAR ST
SHERBORN
FRAMINGHAM
HYDE PARK
EDGAR
W.MEDWAY
POTTER
NEEDHAM
CANTON
LTON
NORWOOD
NORWELL
MEDWAY
HOLBROOK
MARSHFIELD
UXBRIDGE
NEA BELLINGHAM
STOUGHTON
W.WALPOLE
(The W.Walpole-Holbr brought into new 34!
MILLENIUM
BELMONT
DUXBURY
NOW ST.
ANP BLACKSTONE
ANP BELLINGHAM
S.WRENTHAM
RIVERSIDE
BERRY ST
AUBURN ST
SHERMAN RD
TRACY
EASTON
KINGSTON

Figure 2-1
Greater Boston Area Map

[redacted]

Figure 2-2
Greater Boston Area One Line Diagram (Including Related Interfaces)

2.3 Study Horizon

A five-year and ten-year planning horizon was used for this study based on the most recent CELT report. The study was focused on the projected 2018 peak demand load levels for the five-year horizon and 2023 peak demand load levels for the ten-year horizon utilizing the 2013 CELT forecast.

2.4 Analysis Description

This study evaluated the long term area reliability for the Greater Boston and surrounding areas through testing of the steady state system reliability performance. The system was tested under N-0 (all-facilities-in), N-1 (all-facilities-in, first contingency), and N-1-1 (facility-out, first contingency) conditions for a number of possible operating scenarios with respect to related interface transfer levels and generating unit unavailability conditions.

The following types of analysis were performed:

- **Thermal Analysis** – studies to determine the level of steady-state power flows on transmission circuits under base case conditions and following contingency events.
- **Voltage Analysis** – studies to determine steady-state voltage levels and performance under peak load and light load base case conditions and following contingency events.
- **Short Circuit Analysis** – studies to determine the ability of substation equipment to withstand and interrupt fault current.

The thermal and voltage analysis were conducted at two different load levels; peak load and light load. The light load study was primarily conducted to assess high voltage violations in the Greater Boston area. The Greater Boston area is susceptible to high voltage problems due to the large number of underground cables in this part of the system.

For the various elements having thermal violations and for buses with voltage violations under peak load conditions, a critical load level assessment was performed to determine the Boston RSP subarea load level at which these violations would be eliminated.

The PowerGEM Transmission Analysis and Reliability Assessment (TARA) application[15] version 7.10 was used to conduct all thermal contingency analysis presented in this report. This application allowed for optimization of phase shifter settings and generator redispatch to capture operational responses and processing of multiple base cases against a large number of contingencies.

The PTI program PSS/E version 32 was used for base case development.

Aspen version 11 was used for short-circuit evaluations.

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[15] TARA (Transmission Adequacy and Reliability Assessment) is load flow software tool for identifying and analyzing transmission bottlenecks, DC (linear) & AC (non-linear) contingency analysis, Security Constrained Economic Dispatch (SCED), and Security Constrained Reliability Dispatch (SCRD).

Section 3
Study Assumptions

3.1 Steady State Model Assumptions

3.1.1 Study Assumptions

The Greater Boston steady state models were developed to be representative of the long term projection of the 90/10 summer peak system demand level to assess reliability performance under heavy load conditions. The model assumptions included consideration of a wide range of Greater Boston area generation unit unavailability conditions as well as variations in surrounding area transfer level conditions. A comprehensive summary of the load levels, dispatch conditions and transfer levels can be found in the individual case summaries located in Section 10 of this report.

3.1.2 Source of Power Flow Case Models

The power flow study cases used in this study were obtained from the ISO-NE Model on Demand system with selected upgrades to reflect the system conditions in 2023. The load was modified in this model to obtain the 2018 load levels.

3.1.3 Transmission Topology Changes

The original Greater Boston Needs Assessment base cases were created in April 2012 and included all transmission projects with Proposed Plan Application (PPA) approval in accordance with Section I.3.9 of the Tariff, as of the March 2012 RSP Project Listing. However, in April 2013 the cases were modified to reflect the changes post Forward Capacity Auction (FCA-7). As a part of this process several additional transmission upgrades were added based on the March 2013 project listing were included in the base cases. A list of the upgrades included in the study cases can be found in Section 8.

3.1.4 Generation Assumptions (Additions & Retirements)

Generation projects with a FCM Capacity Supply Obligation as of FCA-7 were included in the study base case. A listing of the recent major new future projects cleared in FCA-1 through FCA-7 and not yet in-service is included below.

New Hampshire

- QP 251 – Laidlaw Berlin (Burgess) Biomass Energy Plant (FCA-4)

Massachusetts

- QP 089 – Cape Wind Turbine Generators (FCA-7)
- QP 196 – Northfield Mountain Uprate 88 MW (FCA-4, 6, and 7)
- QP 387-2 – Footprint (FCA-7)

Rhode Island

- QP 233 – Ridgewood Landfill (FCA-2)

Connecticut

- QP 150 – Plainfield Renewable Energy Project (FCA-3)

A significant sized new unit was cleared in FCA-7 for the Boston RSP subarea and this new generation was modeled in the study cases. The unit is identified as Footprint (Queue Position #387-2), also known as Salem 5 & 6 Generation. This new generation was included in the Greater Boston area analysis as shown in Table 2-1 above. The plant consists of two combined cycle units configured as four generators. Each pair is to be made up of 203 MW and 134 MW generators. The total combined out of both units is modeled 674 MW in this assessment. These units are expected to be in service by June 1, 2016.

The existing Salem Harbor units 1 through 4 have retired and these units have been removed from all base cases used in the study.

Generation was modeled at its qualified capacity per FCA-7.

Retirement sensitivity cases capturing potential generation retirements were created to represent the potential retirement of a unit at Mystic Station. This possible retirement condition was evaluated under various transfer level conditions to assess the potential impact of such events on the future reliability of the system as compared to the systems performance absent the retirement of Mystic 7. The Solutions Study intended to address the problems and concerns identified in this Needs Assessment will consider the design cases to develop the base set of solutions and will identify the incremental upgrades associated with the Mystic 7 retirement sensitivity.

3.1.5 Explanation of Changes Not Included

All known system changes for the area under study were included in the study cases. Transmission upgrades that have not been fully developed and generation additions that have not cleared in the 2013 FCA-7 were not modeled due to the uncertainty concerning these proposed system additions.

Additionally, as a part of the case refresh in April 2013, certain transmission projects that are electrically located a significant distance away from the study area and were not expected to have a significant impact on the study area were not included in the model. The following highlight a few prominent projects that were excluded:

- The Pittsfield-Greenfield Solution (RSP ID: 1208-1210, 1221-1226)
- Advanced SWCT – Line 8300 Reconfiguration (RSP ID: 1246)
- Advanced SWCT – Glenbrook to South End 115 kV Cable (RSP ID: 1228)

There are also Non-Price Retirement (NPR) requests from FCA-8 that were not removed from the load flow or short circuit base cases as their determination was made following completion of the analyses supporting this assessment. The units requesting NPR were not considered as having an impact on any of the identified needs for the Greater Boston area. Vermont Yankee and Brayton Point units requested NPRs in FCA-8 but were not removed from the thermal base case models.

Finally, the New England East West Solution (NEEWS) – Central Connecticut Reliability Project components (RSP ID: 576, 1114, 1372, 1373) have PPA approval but are being replaced with the Greater Hartford Central Connecticut projects and are excluded.

3.1.6 Load Forecast Information (including assumptions concerning energy efficiency, interruptible loads, etc.)

The 2013 ISO-NE system load forecast was used as a basis for the demand levels modeled in the study. As of 2012 load modeling for the New England network model is based on forecasted loads as well as forecasts in energy efficiency, passive demand reductions and active demand reductions. The values reported in the 2013 CELT report were used to develop the 2023 and 2018 network load models that were included in the study. Table 3-1 and Table 3-2 below show the aggregate amount of active and passive demand resources modeled in the 2018 and 2023 cases. A more detailed breakdown of demand resource assumptions can be found later in section 3.1.12 showing all forms of demand reductions including availabilities for the different years. Demand Resources were not explicitly modeled in either minimum load level or summer off-peak load level testing as they are already incorporated into the load levels being examined.

Table 3-1 2018 and 2023 DR Modeled in the Basecases

Load Zone	2018 Passive DR (DRV MW) [16]	2018 Active DR (DRV MW)	Total 2018 Available DR (Modeled MW) [17]	2023 Passive DR (DRV MW)[16]	2023 Active DR (DRV MW)	Total 2023 Available DR (Modeled MW) [17]
Maine	182	295	425	230	295	476
New Hampshire	101	61	155	144	61	200
Vermont	159	63	218	233	63	296
Northeast Massachusetts & Boston	456	82	546	682	82	784
Southeast Massachusetts	250	87	333	362	87	451
West Central Massachusetts	314	160	458	450	160	601
Rhode Island	189	74	258	281	74	355
Connecticut	474	324	756	590	324	879
New England	**2,125**	**1,146**	**3,149**	**2,972**	**1,146**	**4,042**

Table 3-2 New England Demand Resource Performance Assumptions

Region	Passive DR	Energy Efficiency	Active DR	RTEGs
New England	100%	100%	75%	0%

3.1.7 Load Levels Studied

The 2023 90/10 summer peak load level was tested. These cases were based on the 2013 CELT report (See Section 7) forecast summer peak 90/10 load level of 34,460 MW for all of New England and the Boston RSP subarea loads were modeled based on a forecasted peak demand level of 7,210 MW[18] or 20.9% of the New England demand which is consistent with area load peak demand assumptions of 20% to 21%. The CELT forecast in Section 7 only has loads until 2022 and the load growth rate from 2021 to 2022 was used to derive the 2023 loads.

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[16] DRV = Demand Reduction Value = the actual amount of load reduced measured at the customer meter; these totals are forecasted values for the commitment period beginning June 1, 2022. These values exclude transmission and distribution losses.

[17] Modeled DR in case includes 100% of Passive DR and 75% of Active DR. The DRV Values are scaled up by 5.5% to account for avoided distribution losses. Modeled MW = 1.055x(100% of Passive DRV + 75% of Active DRV)

[18] The Boston Import area load was derived based on the definition of BOSTON RSP Subarea in the CELT Report.

The 2018 90/10 summer peak load level was tested. These cases were based on the 2013 CELT report forecast summer peak 90/10 load level at 32,615 MW for all of New England and the Boston RSP subarea loads were modeled based on a forecasted peak demand level of 6,830 MW.[19]

Additionally, light load analysis was conducted and this analysis included modeling of system loads at minimum levels as well as under summer off peak load levels. Minimum load levels have been trending in the downward direction and a system load level of 8,500 MW has been established as the most appropriate load level to study when conducting minimum load level analysis. This load level was used for the assessment of minimum load level voltage performance of the Greater Boston area. Based on the current practice of changing the no-load tap position each season of certain transformers in the Greater Boston area, light or off peak loads during summer months could also introduce a voltage concern. Off peak loads were tested at the minimum load level historically seen during summer month periods (New England load at 10,500 MW). Results are included for both the minimum load level and the summer off peak load level conditions.

3.1.8 Load Power Factor Assumptions

Load power factors consistent with the each of the Transmission Owner's planning practices for establishing power factor for loads in the Greater Boston area were assumed for the load model data. The appropriate load power factor was used for each of the load levels modeled.

Peak load power factor was modeled based on the data submitted by the Transmission Owners. Light load high voltage testing was performed at a .998 p.u. leading power factor across New England with the exception of .978 p.u. lagging power factor for NSTAR load in downtown Boston and unity power factor for the NSTAR suburban load.

3.1.9 Transfer Levels

While the current Boston Import N-1 limit is in the range of 4,600 to 4,900 MW, for the purposes of testing the area's reliability, no fixed transfer level was assumed. Instead Boston Import area transfer levels were driven by the various generating unit availability scenarios and are therefore the result of the sum of peak demand in the area minus on-line generating resources. The Boston Import transfer levels for 2023 that were included in the testing ranged from a low of 3,259 MW to a high of 5,075 MW. Additionally cases were run to test a range of interface transfer levels for both the North-South interface and the SEMA/RI interface. The North-South interface levels for 2023 ranged from a high of 2,785 MW to a low of 1,620 MW and the SEMA/RI export values ranged from 2,496 MW to a low of 1,242 MW.

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[19] The 2013 Boston Import area load was derived in the same manner as the 2018 values.

Other relevant interfaces that play a role in the area under study are listed below along with their current maximum transfer level ranges based on the 2013 Federal Energy Regulatory Commission (FERC) 715[20] report for the 2018 system:

- Phase II Import: [redacted]
- East-West: [redacted]
- West-East: [redacted]
- New Brunswick – NE: [redacted]
- Highgate – NE: [redacted]
- Northern New England (NNE) – Scobie +394: [redacted]

New York-New England and other external interfaces were allowed to float within acceptable limits.

Table 3-3 below provides a summary of the transfer levels modeled in all base cases for the significant interfaces associated with the Greater Boston area. Descriptions of the system conditions are shown in Table 3-4.

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[20] http://www.iso-ne.com/system-planning/transmission-planning/ferc-form-no-715-reports

Table 3-3
2018 and 2023 Significant Interface Modeled Transfer Levels

Case Title and Year	East-West	Boston Import	North-South	SEMA/ RI - NE	PHASE II Import
[redacted]	2317	3438	2779	2496	2000
[redacted]	2479	3259	2721	2495	2000
[redacted]	2001	3788	2726	2496	2000
[redacted]	36	3787	2729	2493	0
[redacted]	1987	3802	2725	2495	2000
[redacted]	23	3799	2729	2492	0
[redacted]	2020	3778	2781	2496	2000
[redacted]	1947	3838	2724	2496	2000
[redacted]	1428	4370	2727	2496	2000
[redacted]	1686	4124	2784	2496	2000
[redacted]	1311	4488	2727	2495	2000
[redacted]	1672	4137	2783	2495	2000
[redacted]	735	5072	2728	2494	2000
[redacted]	-429	3438	2759	1816	0
[redacted]	-288	3258	2720	1792	0
[redacted]	606	3790	2717	1243	2000
[redacted]	-813	3787	2718	1790	0
[redacted]	589	3804	2716	1242	2000
[redacted]	-827	3800	2718	1789	0
[redacted]	1168	3780	2753	1795	2000
[redacted]	1109	3840	2752	1794	2000
[redacted]	591	4372	2757	1793	2000
[redacted]	859	4125	2756	1819	2000
[redacted]	473	4489	2757	1791	2000
[redacted]	844	4138	2756	1817	2000
[redacted]	-108	5073	2758	1787	2000
[redacted]	-184	3434	1649	1812	1400
[redacted]	-3	3253	1650	1813	1400
[redacted]	-1230	3776	1646	2488	0
[redacted]	-1246	3793	1647	2487	0
[redacted]	159	3772	1622	2494	1400
[redacted]	101	3831	1623	2493	1400
[redacted]	-424	4363	1619	2492	1400
[redacted]	-185	4118	1622	2492	1400
[redacted]	-541	4480	1619	2490	1400
[redacted]	-197	4129	1622	2491	1400
[redacted]	-1125	5064	1647	2485	1400
[redacted]	2733	3260	2756	2674	2000
[redacted]	2894	3080	2698	2673	2000
[redacted]	2418	3609	2702	2674	2000
[redacted]	458	3608	2708	2673	0
[redacted]	2404	3623	2702	2674	2000

Case Title and Year	East-West	Boston Import	North-South	SEMA/ RI - NE	PHASE II Import
[redacted]	445	3620	2708	2672	0
[redacted]	2437	3599	2758	2674	2000
[redacted]	1847	4191	2704	2675	2000
[redacted]	2364	3659	2701	2675	2000
[redacted]	1731	4308	2704	2674	2000
[redacted]	2105	3945	2761	2674	2000
[redacted]	2091	3957	2761	2674	2000
[redacted]	1158	4892	2706	2673	2000
[redacted]	46	3259	2763	1998	0
[redacted]	186	3079	2724	1974	0
[redacted]	1080	3611	2720	1425	2000
[redacted]	-336	3608	2723	1972	0
[redacted]	1064	3624	2720	1424	2000
[redacted]	-350	3620	2723	1971	0
[redacted]	1640	3600	2755	1975	2000
[redacted]	1065	4192	2760	1974	2000
[redacted]	1581	3660	2755	1975	2000
[redacted]	948	4309	2761	1973	2000
[redacted]	1332	3946	2759	1999	2000
[redacted]	1318	3958	2759	1998	2000
[redacted]	370	4892	2763	1969	2000
[redacted]	291	3254	1654	1994	1400
[redacted]	471	3074	1654	1995	1400
[redacted]	-754	3597	1653	2670	0
[redacted]	-770	3613	1653	2669	0
[redacted]	632	3592	1656	2674	1400
[redacted]	51	4183	1653	2673	1400
[redacted]	574	3652	1655	2674	1400
[redacted]	-66	4300	1653	2671	1400
[redacted]	289	3938	1656	2673	1400
[redacted]	277	3949	1656	2672	1400
[redacted]	-648	4883	1653	2667	1400

Table 3-4 below includes a list of the specific set of base cases (N-0 condition) studied along with a brief description of what conditions the case was intended to represent.

Table 3-4
Summary of System Conditions Modeled

Case Title	Case Description
[redacted]	[redacted]
[redacted]	[redacted]

Case Title	Case Description
	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Case Title	Case Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Additionally, light load (minimum load and summer off peak) level testing included modeling of transfer level conditions appropriate to this load level. The assessment included modeling the North-South transfers at a reduced level, high and low West-East transfers and modeling of Hydro Quebec Phase II at 0 MW and 500 MW.

3.1.10 Generation Dispatch Scenarios

A total of 37 cases were modeled for each of the two study years and used in all the N-1 and N-1-1 contingency testing for the peak load testing which represented a number of possible generation dispatch and availability conditions. The cases all have a major Boston RSP subarea unit out of service as a base condition. The cases are organized by surrounding interface transfer levels. One set is based on high North-South transfers along with high SEMA/RI export levels, the second set is based on high North-South transfers with low SEMA/RI export levels and the final set is based on low North-South transfers with high SEMA/RI export levels.

Based on operational experience, it was assumed that approximately 80% of the fast start units in the Boston RSP subarea were modeled as being in-service.

In addition, combinations of study area resources (Mystic, Kendall, and Footprint) as well as units in close proximity to the Boston RSP subarea (Fore River and HQ Phase II HVDC) were adjusted versus variations of SEMA/RI, western New England, and northern New England units in the system models tested. These dispatch conditions were also combined with the North-South and SEMA/RI interface transfer level variations to create a comprehensive set of possible reliability assessment system conditions.

The cases tested are categorized throughout the report as design cases and retirement sensitivity cases. Design cases include reasonably expected generation unavailability with various New England system transfer stresses. Included in the set of design cases with two critical units out of service were cases with one critical unit out of service, recognizing that one generator out of service in the Boston RSP subarea may potentially highlight different issues than when there is more than one generator out of service, partly due to unit status-dependent system switching [redacted] A criteria violation in a design case constitutes a need that must be addressed by a proposed solution to meet criteria at the load level studied. Additional retirement sensitivity cases representing generation retirement/extended shutdown cases have been tested as well to be consistent with NERC planning criteria. The Solutions Study intended to address the problems and concerns identified in this Needs Assessment will consider both design and retirement sensitivity cases to determine both the robustness of the proposed solutions and to identify the incremental upgrades associated with the sensitivities.

PEAK LOAD DISPATCH CONDITIONS

Design Cases

- **One Critical Unit Out of Service Cases**
  These cases assumed Mystic 8, Mystic 9, Kendall CT, Salem Harbor 5 or Salem Harbor 6 out of service, while simultaneously modeling a range of stressed conditions on the interfaces adjacent to the Boston RSP subarea which included the North-South interface, SEMA/RI interface and the East-West interface.

- **Two Critical Units Out of Service Cases**
  These cases assumed conditions where two critical units are out of service which included various combinations of Mystic7, Mystic 8, Mystic 9, Kendall CT and Salem Harbor 5 or 6 out of service. In addition to assuming two critical units in the Boston RSP subarea out of service the New England system interfaces adjacent to the Boston RSP subarea were modeled with a range of stressed conditions on the interfaces which included the North-South interface, SEMA/RI interface and the East-West interface. The Boston Import transfer level was above the existing limit for these cases.

Generation Retirement Sensitivity Cases

Generation retirement case testing was performed based on stakeholder concerns that the older generating units or stations in the Boston RSP subarea could retire from service in the near future or be subject to extended shutdown. Any needs and resulting solution development will be evaluated with consideration of this possibility.

- **Mystic 7 Retirement Sensitivity**

  These cases assumed the retirement of the Mystic 7 generation. Study cases included two critical units ([redacted] out of service with related interface transfer levels within their respective defined limits. The Boston Import transfer level was above the existing limit for these cases.

Summary of Generation Dispatch Conditions Modeled

The following tables show the unit unavailability and dispatch levels for major generation associated with the Boston RSP subarea and the transfer level conditions for the Boston RSP subarea and related interfaces as modeled for 2023 and 2018 shown in Table 3-5. The numbers in Table 3-5 include the total output of the generators which consists of the qualified capacity and the station service load.

Table 3-5
2018 and 2023 Modeled Generation Dispatch Conditions

Case Title	Fore River	KENDALL CT	MYSTIC			Salem Harbor	
			7	8	9	5	6
[redacted]	697	158	601	698	706	337	0
[redacted]	697	0	601	698	706	337	337
[redacted]	697	158	601	0	706	337	337
[redacted]	697	158	601	0	706	337	337
[redacted]	697	158	601	698	0	337	337
[redacted]	697	158	601	698	0	337	337
[redacted]	697	158	601	698	706	0	0
[redacted]	697	0	0	698	706	337	337
[redacted]	697	158	0	0	706	337	337
[redacted]	697	158	601	0	706	337	0
[redacted]	697	158	601	0	0	337	337
[redacted]	697	158	601	698	0	337	0
[redacted]	697	158	0	0	0	337	337
[redacted]	697	158	601	698	706	337	0
[redacted]	697	0	601	698	706	337	337
[redacted]	697	158	601	0	706	337	337
[redacted]	697	158	601	0	706	337	337
[redacted]	697	158	601	698	0	337	337
[redacted]	697	158	601	698	0	337	337
[redacted]	697	158	601	698	706	0	0
[redacted]	697	0	0	698	706	337	337
[redacted]	697	158	0	0	706	337	337
[redacted]	697	158	601	0	706	337	0

[redacted]	697	158	601	0	0	337	337
[redacted]	697	158	601	698	0	337	0
[redacted]	697	158	0	0	0	337	337
[redacted]	0	158	601	698	706	337	0
[redacted]	0	0	601	698	706	337	337
[redacted]	697	158	601	0	706	337	337
[redacted]	697	158	601	698	0	337	337
[redacted]	697	158	601	698	706	0	0
[redacted]	697	0	0	698	706	337	337
[redacted]	697	158	0	0	706	337	337
[redacted]	697	158	601	0	706	337	0
[redacted]	697	158	601	0	0	337	337
[redacted]	697	158	601	698	0	337	0
[redacted]	697	158	0	0	0	337	337

LIGHT LOAD DISPATCH CONDITIONS

Light load dispatch conditions were similar for both the minimum load level modeling and the summer off-peak load level modeling. Light load level analysis included modeling of dispatch conditions that are appropriate for this load level. The generation dispatch conditions listed below were modeled for the light load level analysis.

- All Major Boston RSP subarea generation out of service
- Pilgrim and Seabrook generators out of service
- Reduced eastern New England generation
- All pumped hydro units off-line

Minimum load testing was based on the following dispatches:

1. Phase II on at 500 MW with low SEMA/RI export and low North-South transfers
2. Phase II on at 500 MW with medium SEMA/RI export and low North-South transfers
3. Phase II off with low SEMA/RI export and low North-South transfers

In addition the summer off-peak load level cases were tested with the following modifications to Dispatch 1 above:

1. Seabrook on
2. Pilgrim on

3.1.11 Reactive Dispatch Assumptions

Peak Load Assumptions

All area reactive resources were assumed available and dispatched if conditions called for their dispatch. Reactive output of units was constrained to defined limits and shunt reactive resources were dispatched as conditions called for. A summary of the reactive output of units and shunt devices connected to the transmission system that play a significant role in the study area can be found in the generation summary tables included in Section 10 and a list of shunt reactive devices modeled in the Boston RSP subarea area can be found in Table 10-2 in Section 10 below.

Light Load Assumptions

The following system adjustments were used for both the minimum load level and summer off-peak load level testing.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

NSTAR Autotransformer Taps

The no load taps on the following NSTAR autotransformers were adjusted to match the light load setting:

[redacted] [redacted]
[redacted] [redacted]
[redacted] [redacted]
[redacted] [redacted]
[redacted] [redacted]

[redacted]

[redacted]

3.1.12 Demand Resource Assumptions

Demand Resources (DR) were modeled in the base cases consistent with current practices for inclusion of demand resources. Demand Resources were modeled in peak load base cases as detailed in Table 3-6 and Table 3-7 below. The passive and active demand reductions are constant for the 2018 and 2023 system conditions. The differences for the two study years' is based on energy efficiency forecasts. In Table 3-6 below the variable forecasted energy efficiency for 2018 and 2023 is lumped together with the fixed passive demand reductions through FCA-7 to provide the total passive DR that was modeled for the years 2018 and 2023.

Table 3-6 2018 and 2023 Passive DR Values: DR through FCA #7 and EE Forecast

Load Zone	Passive DR[21] (FCA-1-7 DRV MW) [22]	EE Forecast (2017-2018 DRV MW) [22]	EE Forecast (2017-2023 DRV MW)[22]	Total 2018 Passive DR (DRV MW) [22]	Total 2023 Passive DR (DRV MW)[22]
Maine	159	23	71	182	230
New Hampshire	80	21	64	101	144
Vermont	125	34	108	159	233
Northeast Massachusetts & Boston	341	115	341	456	682
Southeast Massachusetts	194	56	168	250	362
West Central Massachusetts	245	69	205	314	450
Rhode Island	142	47	139	189	281
Connecticut	417	57	173	474	590

---

[21] Passive DR includes passive DR cleared through FCA #7 as well as forecasted Energy efficiency for the study year

[22] DRV = Demand Reduction Value = the actual amount of load reduced measured at the customer meter; these totals are forecasted values for the commitment period beginning June 1, 2022. These values exclude transmission and distribution losses.

New England	**1,703**	**422**	**1,269**	**2,125**	**2,972**

Table 3-7 FCA #7: Active DR Values through FCA-7

Dispatch Zone	Active DR (FCA-1-7) DRV (MW)
Bangor Hydro	56
Maine	207
Portland, ME	32
New Hampshire	49
New Hampshire Seacoast	12
Northwest Vermont	38
Vermont	25
Boston, MA	62
North Shore Massachusetts	20
Central Massachusetts	51
Springfield, MA	31
Western Massachusetts	78
Lower Southeast Massachusetts	18
Southeast Massachusetts	69
Rhode Island	74
Eastern Connecticut	53
Northern Connecticut	100
Norwalk-Stamford, Connecticut	45
Western Connecticut	126
New England Total	**1,146**

3.1.13 Description of Existing and Planned Protection and Control System Devices Included in the Study

There are a number of Special Protection Systems (SPS) that are designed to operate in and around the Greater Boston study area. These SPSs have, in some cases, been in service for a significant period of time.[23] Each of these SPSs was either modeled directly or taken into consideration when reviewing results. Table 3-8 below lists the SPSs that potentially affect the Greater Boston transmission system.

---

[23] [redacted] have been in service since prior to1990.

Table 3-8
Greater Boston Area Special Protection Systems

SPS Name	SPS Action Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

---

[24] The “stability” mode for [redacted] was not modeled in the study.

3.1.14 Explanation of Operating Procedures and Other Modeling Assumptions

The Greater Boston area transmission power flows are managed on a daily basis through the use of generation dispatch and phase shifting transformers located at [redacted]. The phase shifters are located on the 115 kV systems inside the Boston RSP subarea and are set to balance power flows under normal conditions and are adjusted to post contingency, as necessary.

For the purposes of the contingency testing conducted as part of this study, phase shifters were adjusted to angles expected to work best for post contingency conditions based on phase shifter optimization analysis included in the power flow testing application. These settings were not representative of pre-contingency phase shifter positions. Rather they were set to post contingency angles, within an appropriate operating range of the phase shifters to minimize potential overloads following a contingency. This avoided reporting of overloads for which phase shifter action would serve as the mitigating measure. Further adjustment of the phase shifters was also found to be effective at relieving other overloads post-contingency for overloads that did not exceed STE ratings for elements on the Greater Boston transmission system. It should be noted that phase shifter tap settings were adjusted to unit specific values to accurately model the actual tap settings available on each phase shifting transformer.

Generation adjustments were also modeled in the analysis to reflect system adjustments that could occur between outages under N-1-1 contingency conditions. These adjustments were primarily limited to [redacted]. The adjustments were limited to a total of 1,200 MW across the New England system to reflect consistency with operating reserve constraints. The units listed in Table 3-11 were included in the set of units used for system adjustments between contingencies. Units that are shown with an adjustment type of "Full Dispatch" were allowed to vary their dispatch either up or down if on-line in the case whereas units that are shown with an adjustment type of "Back-Down Only" could only reduce output in response to potential overloads. It should be noted that the unit adjustment process used in the analysis attempts to correct for all overloads that are the results of an initial element outage followed by any one of the subsequent contingencies included in the analysis. The analysis may result in adjustments that allow some elements to overload in an effort to relieve overloads for a number of other elements. The results provided are the best overall system adjustments needed to minimize the total number of overloads for all second level contingencies.

As stated in Section 3.1.11, for the purposes of conducting voltage assessments it is important to note that a number of autotransformers in the Greater Boston area have their no-load tap positions adjusted each season to better optimize the voltage performance of the system between peak load conditions and shoulder period (Spring and Fall) load conditions.

Table 3-9
Units That Were Allowed to Adjust Between Contingencies

Unit Name	Adjustment Type	Unit Name	Adjustment Type
Boston Units		**Western NE Units**	
Framingham Jets	[redacted]	New Haven Harbor	[redacted]
Kendal Jet	[redacted]	Lake Road 1	[redacted]
L Street Jet	[redacted]	Montville 6	[redacted]
Mystic Jet	[redacted]	Westbrook C1, C2 & ST	[redacted]
W Medway Jet 1, 2 & 3	[redacted]	C. Cove	[redacted]
MATEP 3	[redacted]	**Northern NE Units**	
MATEP Diesels	[redacted]	Granite GT	[redacted]
MBTA Jet	[redacted]	Newington G	[redacted]
Waters River J1	[redacted]	Merrimack ST & CT	[redacted]
Mystic 7	[redacted]	MIS C1, C2 & ST	[redacted]
Mystic 8	[redacted]	**SEMA/RI Units**	
Mystic 9	[redacted]	Cherry Street Diesels	[redacted]
Salem Harbor 5	[redacted]	Fitchburg	[redacted]
Salem Harbor 6	[redacted]	Canal 2	[redacted]
Kendal ST & CT	[redacted]	Brayton Point 3	[redacted]
HVDC Terminals		**Greater Boston Units**	
Phase 2 HVDC 1 Terminal	[redacted]	Fore River	[redacted]
Phase 2 HVDC 1 Terminal	[redacted]	ANP Bellingham	[redacted]
CSC Terminal	[redacted]	Ipswich Diesels	[redacted]
		Marblehead	[redacted]

Additionally, operator initiated system adjustments were assumed to be available as mitigating measures for certain conditions. In some cases closing of bus tie breakers that are normally operated open or that can be opened under certain dispatch conditions were assumed to be viable operator responses to certain overloads under appropriate conditions. [redacted]

3.2 Stability Modeling Assumptions

3.2.1 Study Assumptions

Not Applicable.

3.3 Short Circuit Model Assumptions

3.3.1 Study Assumptions

The short circuit analysis assumptions used for this study are consistent with those used for all other studies for this region of the New England system. The case that was developed was intended to be representative of the transmission and generation system configuration that would be in place by 2018.

3.3.2 Short Circuit Model

The study model was based on the ISO-NE's 2013 Master Short Circuit case updated with the addition of generators and transmission lines expected to be in service by 2017. The case used was developed from Round 8 of the New England Short-Circuit database release. A listing of the system topology changes included in the short circuit model is shown in Table 8-2 included in Section 8.

3.3.3 Contributing Generation Assumptions (Additions & Retirements)

The generation model included new generation that cleared FCA-7 as well as PPA approved generators in the vicinity of the study area. In particular this included a new plant (Footprint) to be sited at the existing Salem Harbor plant location. Additionally, units requesting non-price retirements in FCA-8 were not removed from the case as these requests were still under review at the time the analyses supporting this study. This included the Vermont Yankee, Norwalk Harbor 1 & 2, and Brayton Point 1, 2, 3, & 4 units. These units were modeled as in service and running for the short-circuit analysis.

3.3.4 Generation and Transmission System Configurations

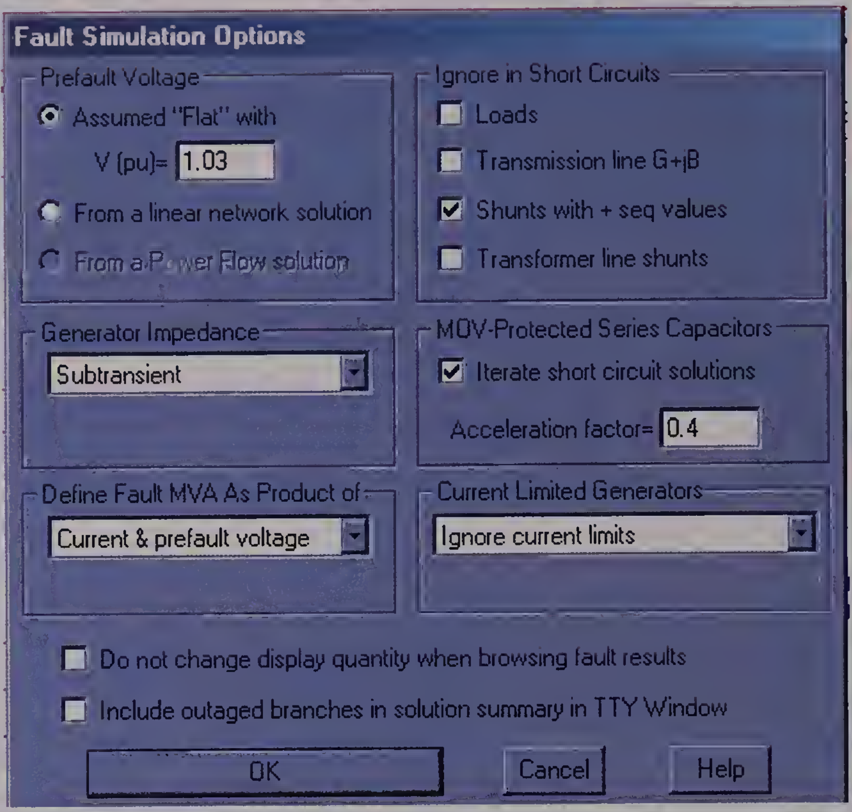
A significant system configuration factor was that the testing assumed [redacted].

3.3.5 Boundaries

Case boundaries were consistent with the New England short-circuit database model assumptions and no additional equivalent source models were added to the case.

3.3.6 Other Relevant Modeling Assumptions

The following options were set with respect to the fault simulation options:


Fault Simulation Options

Prefault Voltage
- ● Assumed "Flat" with
  V (pu)= 1.03
- ○ From a linear network solution
- ○ From a Power Flow solution

Ignore in Short Circuits
- ☐ Loads
- ☐ Transmission line G+jB
- ☑ Shunts with + seq values
- ☐ Transformer line shunts

Generator Impedance: Subtransient

MOV-Protected Series Capacitors
- ☑ Iterate short circuit solutions
- Acceleration factor= 0.4

Define Fault MVA As Product of: Current & prefault voltage

Current Limited Generators: Ignore current limits

- ☐ Do not change display quantity when browsing fault results
- ☐ Include outaged branches in solution summary in TTY Window

The pre-fault voltage was set to 1.03 for National Grid and NSTAR buses and 1.05[25] for Public Service of New Hampshire (PSNH) buses as per respective company-specific practices.

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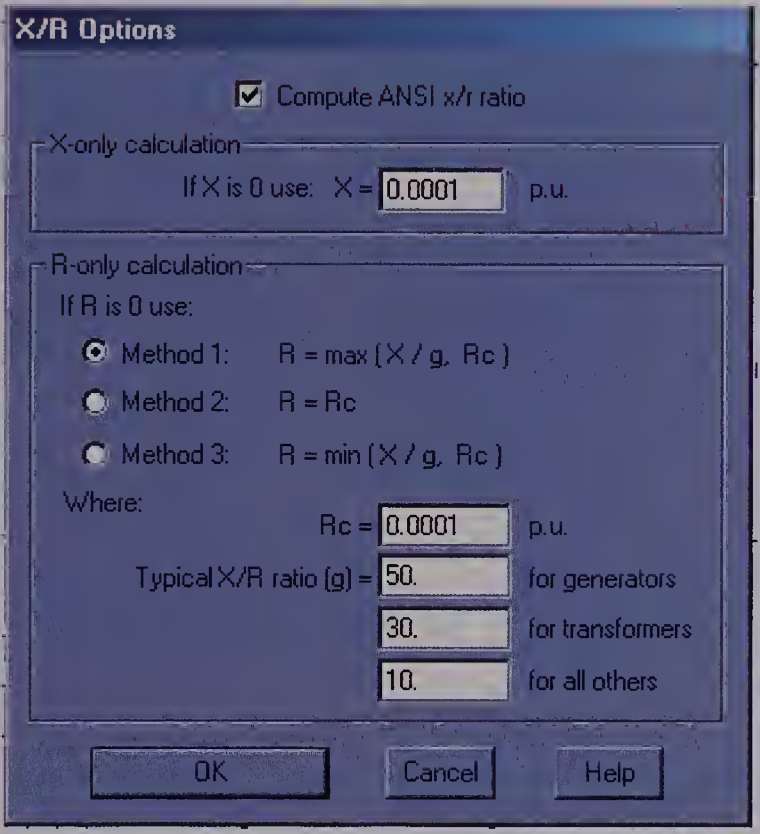
[25] The Planning Technical Guide states that the pre-fault voltage for the PSNH system should be 1.04. Since no overdutied breakers were seen in the PSNH system the analysis was not redone with the lower pre-fault voltage

The following options were set with respect to the X/R options:



X/R Options

☑ Compute ANSI x/r ratio

X-only calculation

If X is 0 use: X = 0.0001 p.u.

R-only calculation

If R is 0 use:

● Method 1: R = max (X / g, Rc)

○ Method 2: R = Rc

○ Method 3: R = min (X / g, Rc)

Where:

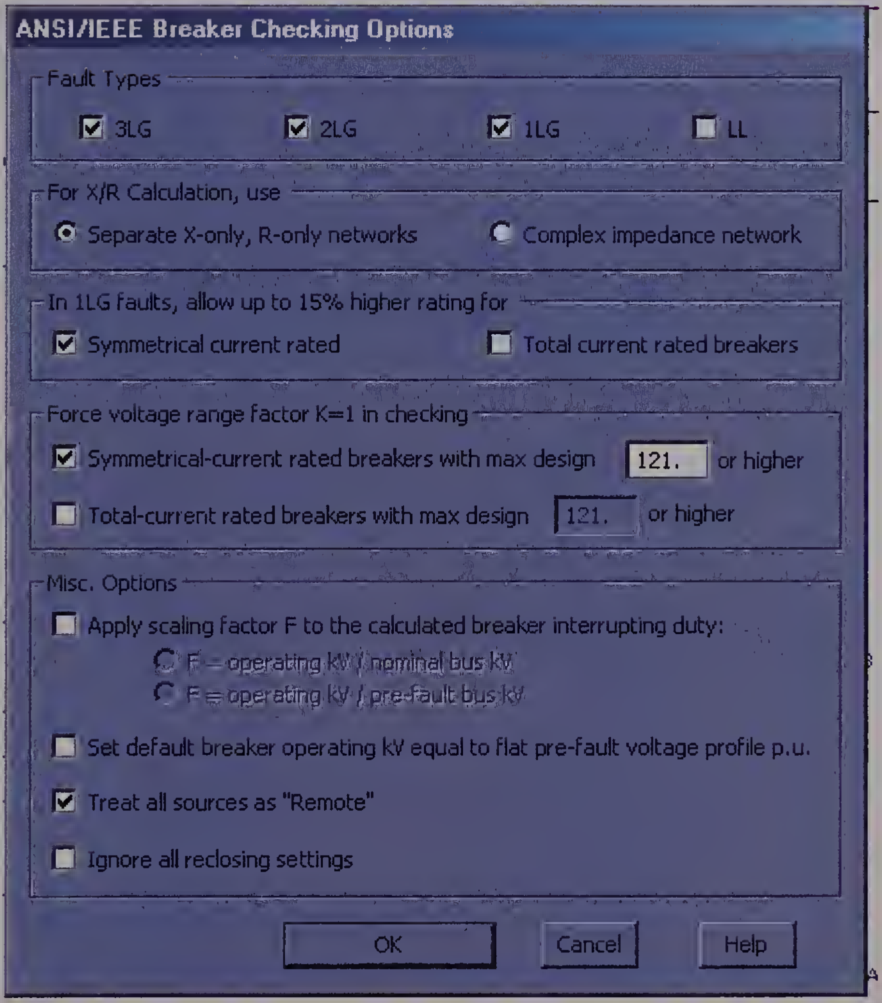
Rc = 0.0001 p.u.

Typical X/R ratio (g) = 50. for generators

30. for transformers

10. for all others

The following provides assumptions used for the Breaker Rating Module:



ANSI/IEEE Breaker Checking Options

Fault Types

☑ 3LG ☑ 2LG ☑ 1LG ☐ LL

For X/R Calculation, use

● Separate X-only, R-only networks ○ Complex impedance network

In 1LG faults, allow up to 15% higher rating for

☑ Symmetrical current rated ☐ Total current rated breakers

Force voltage range factor K=1 in checking

☑ Symmetrical-current rated breakers with max design 121. or higher

☐ Total-current rated breakers with max design 121. or higher

Misc. Options

☐ Apply scaling factor F to the calculated breaker interrupting duty:

○ F = operating kV / nominal bus kV

○ F = operating kV / pre-fault bus kV

☐ Set default breaker operating kV equal to flat pre-fault voltage profile p.u.

☑ Treat all sources as "Remote"

☐ Ignore all reclosing settings

3.4 Other System Studies (such as Transient Network Analysis, Harmonic Analysis, Equipment Assessments, etc.)

Not applicable for this study.

3.5 Changes in Study Assumptions

There have been a significant number of changes in study assumptions and system topologies since the Needs Assessment was first initiated in late 2008. The following is a summary of the most significant changes that have occurred followed by a chronology of reports provided to the Planning Advisory Committee (PAC).

3.5.1 Changes in Load Forecast

Since 2008 load forecast data has changed in a slightly downward direction. However the New England system peak demand load level forecast over this time period has decreased by less than 4%. The table below provides a summary of the 90/10 summer peak demand forecast for 2018 for each of the CELT forecasts published from 2008 through 2013.

Table 3-10
CELT Report Load Forecast History

CELT Forecast Year	2018 90/10 New England Summer Peak
2008 CELT Report	33,830 (extrapolated)
2009 CELT Report	33,235
2010 CELT Report	32,895
2011 CELT Report	32,955
2012 CELT Report	32,675
2013 CELT Report	32,615

The most significant change in study scope since 2008 is the study horizon. In 2008 the study horizon ended in 2018. The current assessment has a study horizon that ends in 2023. A summary of the changes in load modeling assumptions from the initial study to the current study is provided in Table 3-11 below:

Table 3-11 Comparison of Greater Boston Study Load Forecast Assumptions

Assumption Metric	Initial Needs Assessment (July 2010)	Updated Needs Assessment (July 2013)
Study Horizon Yr.	2013 / 2018	2018 / 2023
Load Forecast Basis	2008 CELT 90/10 Summer	2013 CELT 90/10 Summer
New England Peak Load	2013 - 32,410 MW 2018 - 33,830 MW	2018 - 32,615 MW 2023 - 34,460 MW
Boston RSP subarea Peak Load	2013 - 6,460 MW 2018 - 6,900 MW	2018 - 6,830 MW 2023 - 7,210 MW
NEMA/BOSTON Loadzone DR	300 MW through FCA2	457 MW[26] through FCA7
Additional Energy Efficiency	None	2018 – 124 MW 2023 – 369 MW[27]

3.5.2 Changes in System Resources and Topology

Other significant changes in study conditions were the changes in system topology that have occurred since the study was first initiated. The availability of generation resources for the study area was among the most significant changes. In 2010 Dominion announced its intention to retire Salem Harbor units 1 through 4 from the system reducing generation resources for the area by some 750 MW, a reduction of over 20% in area resources. As a result of this announced retirement, additional upgrades have been placed in service to address potential reliability concerns for the area. These changes triggered the need for a full reassessment of area needs.

Subsequent to this announcement a new resource was proposed and ultimately cleared the in FCA-7 which would effectively replace the generation retired at Salem Harbor with new generation. The new generating facility has a qualified capacity of 674 MW. This new generation addition once again changed the resources of the Greater Boston area requiring a full reassessment of area needs.

Other system topology changes also occurred with additions of new step down facilities as well as implementation of system upgrades that were more urgent such as the need to upgrade the Lexington-Trapelo Rd.-Waltham 115 kV lines (320-507/508).

3.5.3 Changes in System Modeling

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[26] The DR number is calculated by adding 8% transmission and distribution losses to the NEMA/BOSTON Passive DR and Boston and North shore Dispatch zone active DR from Table 3-6 and Table 3-7 respectively.

[27] The Forecasted EE number obtained by adding 8% transmission and distribution losses to the NEMA/BOSTON EE forecast number from Table 3-6.

An additional significant study adjustment was the change in system modeling of underground cable systems in the Boston RSP subarea[28]. The design typically used by NSTAR for its underground transmission system includes the construction of companion circuits in a common duct bank where two circuits share cooling fluids in order to maximize thermal cooling capabilities. This construction technique relies on pumping facilities and in some cases heat exchanger facilities to improve the thermal performance of both circuits by circulating cooling fluid from one circuit to the other and back in a looped manner.

One significant consequence of this design is the change in thermal capabilities of a circuit when its companion circuit is out of service. In many cases loss of a companion circuit results in loss of coolant circulation and, consequently, a reduction in thermal cooling. This means that, for modeling purposes, the rating of an underground circuit changes when its companion circuit is out of service requiring the use of alternative rating tables. A modeling change was developed by ISO-NE to capture this change in rating. The process called for a revision to the circuit model to include alternate versions of each underground cable as well as revision to all associated contingency files to use the appropriate cable model depending on the contingency that was being simulated. This change in modeling more accurately captures the thermal capability of underground cables during outage events.

An additional change also occurred related to the ratings used for underground transmission facilities in the NSTAR system. As a follow-up to ISO-NE's request for single line in-service ratings, NSTAR also re-rated underground cables based on new rating practices and to ensure consistency with ISO-NE rating procedure requirements. The new ratings used in the base case models were all based on a 12-hour LTE rating methodology consistent with ISO-NE rating procedures.

A full explanation of the methodology developed to capture this system characteristic is included in Section 12 of this report. Section 12 also includes a summary of the updated ratings that have been developed for the applicable cable pairs showing the companion cable in-service and out-of-service ratings.

There was also a change in assumptions concerning N-1-1 testing. Prior assessments were based on a general practice that included all lines that interconnect two or more BPS stations as the initial element to be taken out of service in N-1-1 testing. This approach changed to be more expansive and the study was modified to include all BES elements in the study area.

3.5.4 Chronology of Needs Assessment Study Effort

The Greater Boston Needs Assessment study progress has been routinely reported at PAC meetings. A chronology of the reports provided to the PAC is shown in Table 3-12 below:

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[28] See April 2013 PAC presentation available at http://www.iso-ne.com/system-planning/key-study-areas/greater-boston.

Table 3-12 Chronology of Greater Boston Study PAC Reviews

PAC meeting date	Discussion topic	Presentation or Report Title[29]
May 20, 2008	Initial announcement of starting Needs Assessment and study scope	Northeast Massachusetts / Greater Boston Transmission Needs Assessment – Study Scope
Jan 21, 2009	Needs Assessment Study status update including initial N-1 results	Greater Boston Transmission System Needs Assessment – Study Results
Jul 16, 2009	Needs Assessment Study Results; Announced of commencement of Solutions Study	Greater Boston Transmission System Needs Assessment Review and Solution Study Initiation
Dec 16, 2009	Revisit Needs Assessment for generator retirement/delist scenarios	Greater Boston Needs Assessment (Status Update)
Mar 18, 2010	Update on Needs Assessment and review of options for potential solutions	Greater Boston Needs Assessment Solutions Status Update (ISO presentation) Greater Boston Transmission Reliability Assessment and Preliminary Discussion of Alternatives (NSTAR presentation)
July 8, 2010	Needs Assessment Report posted to ISO-NE web site	Greater Boston Area Transmission Needs Assessment
Dec 16, 2010	Needs Assessment and Solutions Study update	Greater Boston Study Needs Assessment/Solution Study Status Update
Jun 30, 2011	Needs Assessment and Solutions Study update	Greater Boston Study Needs Assessment/Solution Study Status Update
Jan 18, 2012	Solutions Study update on preliminary preferred solution	Greater Boston Study Needs Assessment/Solution Study Status Update
Mar 14, 2012	Solutions Study update on preliminary preferred solution; NHT proposes HVDC as alternative which ISO-NE agrees to study	Greater Boston Study Needs Assessment/Solution Study Status Update
Feb 12, 2013	Solutions Study update	Greater Boston Solutions Study Status Update
April 2013	NSTAR led discussion on changes to the underground cable ratings	NSTAR Underground Cable Ratings Update
July 9, 2013	Needs Assessment updated with the latest load forecasts and FCA results and Solutions Study update	Greater Boston 2023 Needs Assessment and Solutions Study Status Update
Nov 20, 2013	Solution Study Update	Greater Boston 2023 Solutions Study Status Update

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[29] The PAC presentations are available at http://www.iso-ne.com/system-planning/key-study-areas/greater-boston.

PAC meeting date	Discussion topic	Presentation or Report Title[29]
June 19, 2014	Disclosure of Cost Estimate for the "AC Plan" and "HVDC Plan"	Greater Boston Solutions Study Update
November 18, 2014	Greater Boston Solutions Study Update	Greater Boston 2023 Solutions Study Status Update

Section 4
Analysis Methodology

4.1 Planning Standards and Criteria

The applicable NERC, NPCC and ISO-NE criteria were tested as part of this evaluation. A description of each of the NERC, NPCC and ISO-NE standard tests that were included in all studies used to assess system performance are shown in Table 4-2 in Section 4.3.2.

4.2 Performance Criteria

4.2.1 Steady State Criteria

The Needs Assessment was performed in accordance with NERC TPL-001-4 Transmission System Standards, NPCC "Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System", dated 04/20/12 the ISO New England Planning Procedure 3, "Reliability Standards for the New England Area Bulk Power Supply System," the ISO New England Planning Procedure 5-3, "Guidelines for Conducting and Evaluating Proposed Plan Application Analyses", as well as criteria found in Section 11.

NERC Reliability Standards require that the system thermal and voltage levels remain within applicable limits after the events as described in "Table I. Transmission System Standards – Normal and Emergency Conditions" of the NERC Reliability Standard TPL001-4.

Steady State Thermal and Voltage Limits

A summary of the criteria used to assess system performance for thermal and/or voltage violations used in the study are included in Section 11.

Steady State Solution Parameters

The pre-contingency and post-contingency solution parameters that were used for adjustment of area interchange, adjustment of load tap-changing transformers (LTCs), static var devices (SVDs, including automatically-switched capacitors) and phase angle regulators (PARs) were modeled as described below.

Table 4-1
Study Solution Parameters

Case	Area Interchange	Transformer LTCs	Phase Angle Regulators	SVDs & Switched Shunts
Pre-contingency	Disabled	Stepping	Locked[30]	Regulating
Post-contingency	Disabled	Stepping	Locked	Regulating

4.2.2 Stability Performance Criteria

Not Applicable.

4.2.3 Short Circuit Performance Criteria

The criteria used to determine short circuit duty adequacy was consistent with recognized industry standards. ISO-NE Planning Procedure 3, Section 3.3 states "The New England bulk power supply system shall be designed to ensure equipment capabilities are adequate for fault current levels with all transmission and generation facilities in-service for all potential operating conditions." These procedures were used in the evaluation of fault duties as compared to interrupting capability of all applicable equipment.

There were internal Transmission Owner standards that provided additional guidance extending beyond these standards which included such consideration as assumptions concerning the appropriate pre-fault voltage conditions. Pre-fault voltage conditions were established by the Transmission Owners based on their experience for the particular areas under study.

4.2.4 Other Performance Criteria (as appropriate)

Not Applicable.

4.3 System Testing

4.3.1 System Conditions (Sensitivities) Tested (including operating and equipment condition assumptions)

System-condition-testing included evaluation of system performance under a number of generating unit outage conditions as well as unit retirement scenarios, variations in related transfer and area import level conditions, as well as a significant number of line/transformer out of service conditions.

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[30] Boston Area PARs set to optimized settings

4.3.2 Steady State Contingencies / Faults Tested

Contingencies in each of the following NERC, NPCC and ISO-NE reliability criteria categories were tested as part of this evaluation.

Table 4-2
Summary of NERC, NPCC and ISO-NE Category Contingencies to be Tested

Contingency Type	NERC Type	NPCC D-1 Section	ISO-NE PP-3 Section	Tested in This Study
All Facilities in-service	P0	5.4.2.b	3.2.b	Yes
Generator (Single Unit[31])	P1.1	5.4.1.a	3.1.a	Yes
Transmission Circuit	P1.2	5.4.1.a	3.1.a	Yes
Transformers	P1.3	5.4.1.a	3.1.a	Yes
Shunt Devices	P.1.4	5.4.1.a	3.1.a	Yes
Single Pole DC line	P.1.5	5.4.1.a	3.1.a	Yes
Element w/o Fault	P2.1	5.4.1.d	3.1.d	Yes
Bus Section	P2.2	5.4.1.a	3.1.a	Yes
Breaker Failure	P.2.3, P.2.4, P4	5.4.1.e	3.1.e	Yes
Double Circuit Tower	P.7.1	5.4.1.b	3.1.b	Yes
Bipolar DC line	P.7.2	5.4.1.f	3.1.f	Yes

Additionally, to cover NERC TPL 001-4 P3 and P6, and NPCC and ISO-NE criteria, N-1-1 testing was performed as follows:

- An initial contingency of a transmission circuit or generator in the study area was taken
- System adjustments were performed between contingencies
- All the contingencies in Table 4-2 were applied as second contingencies

The details of all the contingencies tested are provided in Section 12.

4.3.3 Stability Contingencies / Faults Tested

Not applicable.

[redacted]

4.3.4 Short Circuit Faults Tested

Short circuit faults were evaluated for three phase, phase to ground and double line phase to ground fault conditions. The assessment evaluated the maximum fault duty that would be seen from these types of fault conditions for each circuit breaker in the study area. Fault duties were evaluated at the following major Greater Boston Area stations:

Table 4-3
Greater Boston Area Stations Considered for Short Circuit

Station	Station	Station
Andrews Square 115 kV	Kingston 345 kV	Seabrook 345 kV
Baker Street 115 kV	K-Jet2 13.8kV	Seabrook 24.5 kV
Brighton 115 kV	K Street 115 kV	Sherborn 115.kV
Burlington 115 kV	K Street 345 kV	Shrewsbury 69 kV
Canton 115 kV	Lexington 115 kV	Slayton Hill 115 kV
Chelsea 115 kV	Lexington 345 kV	Speen St 115 kV
Colburn Street 115 kV	Lynn115 kV	Stoughton 345 kV
Deer Island 115.kV	Maplewood 115 kV	Sudbury 115 kV
Dewar Street115 kV	Maynard 115.kV	Tewksbury 115 kV
Dover 115 kV	Medway 115 kV	Tewksbury 230 kV
E Holbrook 115 kV	Merrimack 115 kV	Tewksbury 345 kV
E Methuen 115 kV	Mystic 345.kV	W Boylston 115 kV
E Cambridge 115.kV	Mystic115 kV	W Methuen 115 kV
Edgar 115 kV	N Cambridge 115 kV	Wachusett 115 kV
Everett 115 kV	N Cambridge 345 kV	Wakefield Jct 115kV
Fitch 69 kV	Needham 115.kV	Wakefield Jct 345kV
Framingham 115 kV	Northboro Road 115 kV	Walpole 115 kV
Golden Hills 115 kV	North Quincy 115 kV	Waltham 115 kV
Greendale 115 kV	Pratts Junction 115 kV	Ward Hill 115 kV
Hartwell 115 kV	Read Street 115 kV	Ward Hill 345 kV
Holbrook 115 kV	Revere 115 kV	W Framingham 115 kV
Holbrook 345 kV	Rolfe Avenue 115 kV	W Medway 345 kV
Hyde Park 115 kV	S Danvers 115 kV	Woburn 115 kV
Hyde Park 345 kV	Salem Harbor 115 kV	Woburn 345 kV
Kendall 115 kV	Sandy Pond 115 kV	W Walpole 115 kV
Kingston 115 kV	Sandy Pond 345 kV	W Walpole 345 kV

Section 5
Results of Analysis

5.1 Overview of Results

The results of the steady-state analysis for all of the study work completed indicated that there no N-0 overloads or voltage violations. However, there were a number of overloads and voltage violations for N-1 and N-1-1 conditions. The results of the short-circuit work indicated there were a number of breakers overdutied and a number with limited short-circuit margin.

The results shown in sections 5.2.1 through 5.2.3 below include results for thermal overloads (STE violations are designated by "STE" after the overload percentage), low voltage violations and high voltage violations (see Section 11 for voltage criteria). The low voltage criteria analysis was based on peak load conditions. Due to the operating practice of changing no-load taps on autotransformers for some of the units in the Boston RSP subarea high voltage criteria assessments were conducted for both minimum load conditions, occurring in the Spring and Fall, and off-peak load conditions, occurring during Summer off-peak periods.

An overview of the results of the testing performed has been organized by subareas within the study area. The set of the defined subareas was developed based on a review of the thermal and voltage violations that were specific to particular areas within the Greater Boston study area. As a result the Greater Boston area results were grouped into eight subareas. These include the following subareas:

A. 345 kV And 115 kV Northern Ties to Greater Boston
B. Waltham, Woburn and Lexington Area
C. Downtown Boston 115 kV Cables
D. Sudbury, Marlboro and Northborough Area
E. W. Medway, W. Walpole and Holbrook Area
F. Boston, Golden Hills and Wakefield Junction Area
G. 115 kV Lines North of Boston in Salem Area and Near Tewksbury[32]
H. 115 kV Lines Near Tewksbury

The geographic location of the defined subareas in which these concerns were observed is shown in Figure 5-1 below.

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[32] Sub-Area G (115 kV Lines North of Boston in Salem Area and Near Tewksbury) was studied but, due to recent upgrades, which include the Salem Harbor retirement upgrades, and the addition of new resources this sub-area was found to no longer result in any reportable reliability issues.)

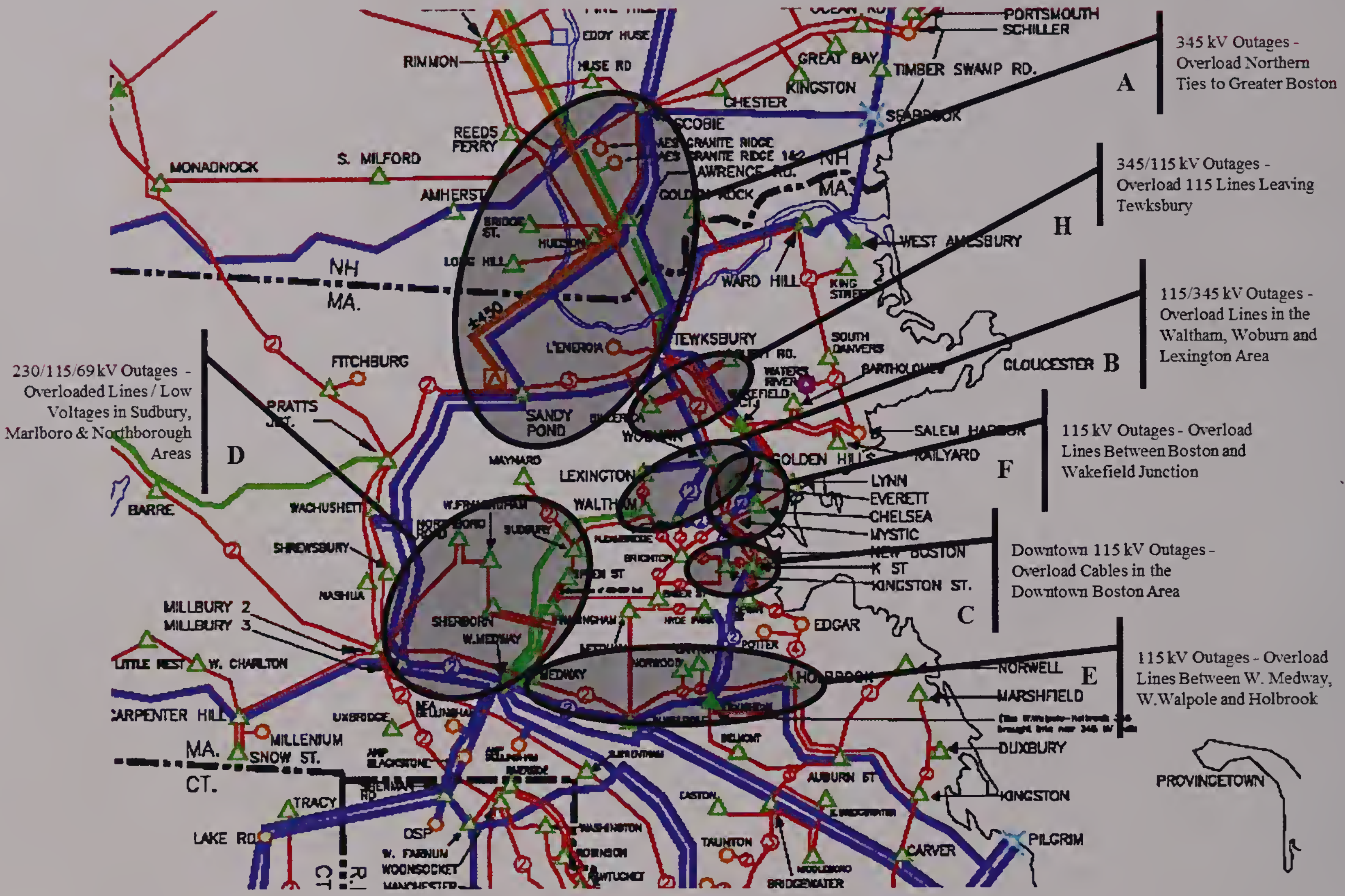
345 kV Outages - Overload Northern Ties to Greater Boston
A
345/115 kV Outages - Overload 115 Lines Leaving Tewksbury
H
115/345 kV Outages - Overload Lines in the Waltham, Woburn and Lexington Area
B
230/115/69 kV Outages - Overloaded Lines / Low Voltages in Sudbury, Marlboro & Northborough Areas
D
115 kV Outages - Overload Lines Between Boston and Wakefield Junction
F
Downtown 115 kV Outages - Overload Cables in the Downtown Boston Area
C
115 kV Outages - Overload Lines Between W. Medway, W.Walpole and Holbrook
E
PORTSMOUTH
SCHILLER
EDDY HUSE
HUSE RD
RIMMON
GREAT BAY
TIMBER SWAMP RD.
KINGSTON
CHESTER
SEABROOK
SCOBIE
REEDS FERRY
AES GRANITE RIDGE
LAWRENCE RD.
GOLDEN ROCK
MONADNOCK
S. MILFORD
AMHERST
BRIDGE ST.
HUDSON
LONG HILL
NH
MA.
WEST AMESBURY
WARD HILL
KING STREET
L'ENERGIA
TEWKSBURY
SOUTH DANVERS
FITCHBURG
PRATTS JCT.
SANDY POND
WOBURN
WAKEFIELD
BARTHOLOMEW
GLOUCESTER
SALEM HARBOR
RAILYARD
GOLDEN HILLS
MAYNARD
LEXINGTON
WALTHAM
LYNN
EVERETT
CHELSEA
MYSTIC
NEW BOSTON
K ST
KINGSTON ST.
BARRE
WACHUSETT
SHREWSBURY
SUDBURY
BRIGHTON
NASHUA
SHERBORN
W.MEDWAY
EDGAR
MILLBURY 2
MILLBURY 3
LITTLE REST
W. CHARLTON
MEDWAY
NORWOOD
HOLBROOK
NORWELL
MARSHFIELD
CARPENTER HILL
UXBRIDGE
MILLENIUM
SNOW ST.
BELMONT
DUXBURY
MA.
CT.
TRACY
BLACKSTONE
PROVINCETOWN
KINGSTON
AUBURN ST
EASTON
LAKE RD
OSP
W. FARNUM
WOONSOCKET
WASHINGTON
ROBINSON
TAUNTON
CARVER
PILGRIM
BRIDGEWATER

Figure 5-1
Greater Boston Subareas of Concern

A brief summary of each of the problems found in the subareas for the design case and retirement sensitivity case conditions is provided below in Table 5-1 through Table 5-7. Further explanation of the worst case observed thermal and voltage violations is included in Sections 5.2.1 through 5.2.3 below. Complete results of N-0, N-1 and N-1-1 testing are documented in the tables included in Section 13.

An additional designation which helped group common elements within each subarea was also developed for reporting purposes. A designation of C-7, for example, was indicative of grouping of the 324 and 372 cables, both of which run from Mystic to Kingston stations within Subarea C. Similarly a designation of C-5 is a grouping of the 110-510, 110-511, 514-510 and 514-511 cables which collectively interconnect the Baker St., Brighton and Kingston stations within Subarea C. Circuits were grouped together in this manner to ensure all like elements, in terms of common paths, were reported together. This report grouping was developed at the beginning of the Greater Boston study and, as the study results have changed over time, there are some elements that are no longer showing overloads. For example, the element grouping designated as A-6 was established for the G-133E and G-133W circuits which in earlier studies were reported as overloaded but do not currently show any overloads. Consequently, there may be element designations that are no longer included in the overloaded element reports and are therefore not included in the tables or descriptions shown below.

Subarea A - 345 kV and 115 kV Northern Ties to Greater Boston

Table 5-1 Subarea A - N-0, N-1, and N-1-1 Steady State Violations

Sub Area	Case Category	N-0	N-1	N-1-1
A – 345 kV and 115 kV Northern Ties to Greater Boston	Design Case Violations	No Violations	[redacted]	[redacted]
				[redacted]
			[redacted]	[redacted]
				[redacted]
				[redacted]
				[redacted]
				[redacted]
				[redacted]
				[redacted]
	Additional Retirement Sensitivity Case Violations	No Violations	[redacted]	[redacted]
			[redacted]	[redacted]

Subarea B – Waltham, Woburn and Lexington Area

Table 5-2 Subarea B - N-0, N-1, and N-1-1 Steady State Violations

Sub Area	Case Category	N-0	N-1	N-1-1
B – Waltham, Woburn and Lexington Area	Design Case Violations	No Violations		[redacted]
			[redacted]	[redacted]
			[redacted]	[redacted]
			[redacted]	[redacted]
			[redacted]	[redacted]
				[redacted]
				[redacted]
			[redacted]	[redacted]
				[redacted]
	Additional Retirement Sensitivity Case Violations	No Violations	[redacted]	[redacted]
			[redacted]	[redacted]
				[redacted]

Subarea C - Downtown Boston 115 kV Cables

Table 5-3 Subarea C - N-0, N-1, and N-1-1 Steady State Violations

Sub Area	Case Category	N-0	N-1	N-1-1
C – Downtown Boston 115 kV Cables	Design Case Violations	No Violations	[redacted]	[redacted]
				[redacted]
			[redacted]	[redacted]
			[redacted]	[redacted]
			[redacted]	[redacted]
			[redacted]	[redacted]
			[redacted]	[redacted]
				[redacted]
				[redacted]
	Additional Retirement Sensitivity Case Violations	No Violations	[redacted]	[redacted]

Subarea D - Sudbury, Marlboro and Northborough Area

Table 5-4 Subarea D - N-0, N-1, and N-1-1 Steady State Violations

Sub Area	Case Category	N-0	N-1	N-1-1
D – Sudbury, Marlboro and Northborough Area	Design Case Violations	No Violations	[redacted]	[redacted]
				[redacted]
			[redacted]	[redacted]
				[redacted]
				[redacted]
				[redacted]
				[redacted]
				[redacted]
				[redacted]
				[redacted]
				[redacted]
			[redacted]	[redacted]
			[redacted]	[redacted]
				[redacted]
	Additional Retirement Sensitivity Case Violations	No Violations	[redacted]	[redacted]

Subarea E – W. Medway, W. Walpole and Holbrook Area

Table 5-5 Subarea E - N-0, N-1, and N-1-1 Steady State Violations

Sub Area	Case Category	N-0	N-1	N-1-1
E – Holbrook and W. Walpole Area	Design Case Violations	No Violations	[redacted]	[redacted]
				[redacted]
				[redacted]
				[redacted]
			[redacted]	[redacted]
				[redacted]
			[redacted]	[redacted]
			[redacted]	
	Additional Retirement Sensitivity Case Violations	No Violations		[redacted]
				[redacted]
				[redacted]
				[redacted]
				[redacted]

Sub Area	Case Category	N-0	N-1	N-1-1
				[redacted]

Subarea F - Boston, Golden Hills and Wakefield Junction Area

Table 5-6 Subarea F - N-0, N-1, and N-1-1 Steady State Violations

Sub Area	Case Category	N-0	N-1	N-1-1
F – Boston, Golden Hills and Wakefield Junction Area	Design Case Violations	No Violations		[redacted]
				[redacted]
				[redacted]
			[redacted]	[redacted]
			[redacted]	[redacted]
				[redacted]
				[redacted]
				[redacted]
	Additional Retirement Sensitivity Case Violations	No Violations	[redacted]	[redacted]
				[redacted]

Subarea H – 115 kV Lines North of Boston in Salem Area and Near Tewksbury

Table 5-7 Subarea H - N-0, N-1, and N-1-1 Steady State Violations

Sub Area	Case Category	N-0	N-1	N-1-1
H – 115 kV Lines Near Tewksbury Area	Design Case Violations	No Violations		[redacted]
				[redacted]
			[redacted]	[redacted]
				[redacted]
				[redacted]
	Additional Retirement Sensitivity Case Violations	No Violations	[redacted]	[redacted]
				[redacted]
				[redacted]
				[redacted]

5.2 Steady State Performance Criteria Compliance

Steady state test results varied as a function of the system conditions modeled. A number of post-contingency overloads and voltage violations were observed in all of the various base cases modeled and in many cases only the severity of the violations changed. There were also a number of post contingency overloads and voltage violations that were only associated with specific system conditions. A high level summary of the results for the conditions that were modeled is provided in Figure 5-1 above.

5.2.1 N-0 Thermal and Voltage Violation Summary

N-0 conditions were reviewed for the cases modeled. The results indicate that under the dispatch scenarios and transfer levels studied no N-0 condition thermal overloads or voltage violations were observed.

5.2.2 N-1 Thermal and Voltage Violation Summary

N-1 testing was performed for all of the system condition models described in Section 3 above. The results of overloaded lines and voltage violations can be found in the tables included in Appendix G. An overview of the results of N-1 testing is provided below. It should be noted that a number of pre and post contingency concerns seen in simulations were determined to be mitigated through phase shifter response. The operation of the Boston RSP subarea phase shifters are under the supervision of system operators and they routinely evaluate the pre and post contingency conditions of the system to determine the most appropriate phase shifter response to potential overloads. The exact process, response and phase shifter settings that operators use was not included in the study. However, evaluations were performed to determine if phase shifter adjustments could mitigate identified overloads and, in those cases where such actions were viable, overloads shown in model simulations that could be mitigated were not included in the results reporting.

The Holbrook and West Walpole subarea (subarea-E) within the Greater Boston area was found to include the potential for loss of consequential load[33] in excess of 300 MW [redacted]. While there are currently no specific standards that limit the magnitude of consequential load loss, this level of load loss violates the level noted in the draft ISO-NE Load Interruption Guide[34]. [redacted].

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[33] Consequential Load Loss is the interruption of loads that are directly supplied by the faulted elements or affected area. This is usually associated with a radial element but it may be associated with loads fed directly from a network element or from lines on common circuit structures or load lost due to isolation of multiple elements as a result of breaker failures.

[34] See http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2011/load_interruption.pdf

Test results for 2018 and 2023 base case conditions indicated a number of problems that could not be corrected through system adjustments (such as Phase Shifter adjustment,, HVDC output adjustment or SPS actions). The results are reviewed from two perspectives; design level and retirement sensitivity conditions. A summary of the design level system conditions is provided which provide the results that are based on the reliability standard requirements for generator dispatch and transfer level conditions. Additionally, a summary is provided for retirement sensitivity conditions that consider plant retirement conditions.

There were a limited number of voltage violations under N-1 conditions. Subarea D – Sudbury, Marlboro and Northboro and Subarea F – Boston, Golden Hills, and Wakefield Junction, both had a limited number of buses with low voltage violations under 2018 and 2023 peak load conditions.

Additionally under light load testing conditions, Subarea B – Boston, Golden Hills and Wakefield Junction, Subarea C – Downtown Boston 115 kV Cables, Subarea D - Sudbury, Marlboro and Northboro, and Subarea E - Holbrook and West Walpole all had a limited number of buses with high voltage violations under minimum load and/or off peak load conditions.

N-1 Overloads and Voltage Violations by Subarea

The summaries provided in the following tables identify the worst case overloads for system elements for modeled conditions grouped by the subarea that the elements are located in. In many cases overloads occurred for more than one system modeled condition. Only the worst case overloads are listed here in the interest of avoiding repetitive reviews. The worst case overloads due to contingencies reported are organized by the year that was tested and by the category of modeled condition (i.e. Design Cases or Retirement Sensitivity Cases) that the overload occurred for. The element overload summaries for design conditions are indicated with the designation "Des" (i.e. one or two units out of service modeled conditions) and overloads occurring for retirement sensitivity conditions are indicated with the designation "Sen" (i.e. generator retirement) overloads. The tables identify the contingency that caused the worst case overload and the percent overload that was observed. Additionally a high level map shows the location of overloaded elements has been included for each of the subareas. Only the converged cases are reported in the detailed discussion of each subarea. A discussion of divergent cases is included at the end of this section. Please refer to the results tables provided in Appendix I for a full listing of all overload conditions that were observed. Additionally, Appendix G includes a summary table of all overload conditions for each subarea.

Subarea A - 345 kV and 115 kV Northern Ties to Greater Boston

Cases in which transfer levels across the North-South interface were at high levels resulted in overloads on 345 kV lines north of the Boston RSP subarea. [redacted]

[redacted]

Figure 5-2 Subarea A Design (White) and Sensitivity (Shaded) Case Overloaded Elements

Worst Case Thermal Violations for Subarea A

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
A-1	Y-151 Line	Pelham to Power St. 115 kV line (formerly Hudson) section	Des	[redacted]	238	[redacted]	245
			Sen	[redacted]	256	[redacted]	265
		Pelham to Dracut Junction 115 kV line	Des	[redacted]	206	[redacted]	212
			Sen	[redacted]	223	[redacted]	230

There was an issue observed in association with the loss of [redacted] The acceptability of this loading level ([redacted]) will need to be investigated to ensure that the conductor and terminations can withstand this level of loading [redacted]

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
A-2	337 Line	Sandy Pond to Tewksbury 345 kV Line	Des	None		None	
			Sen	[redacted]	104	[redacted]	109

This line overloads for [redacted]abrook. The most severe overload observed was for [redacted]rload. The overloads shown in this table are based on operation of [redacted] and are at a level that may be corrected through other system adjustments (such as back down of the Sandy Pond terminal or additional northern resources). [redacted]. Taking such actions may stress the reserves available on the system to compensate for this loss of source.

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
A-3	394 Line	Seabrook to Ward Hill 345 kV line section	Des	[redacted]	111	[redacted]	113
			Sen	[redacted]	107	[redacted]	109
[redacted]							

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
A-5	Sandy Pond Xfm	Sandy Pond 345/115 kV autotransformer	Des	None		None	
			Sen	None		[redacted]	103
[redacted] This condition only arose in 2023 under retirement case scenarios and may be mitigated through back down of Phase II.							

Worst Case Voltage Violations for Subarea A

There were no design case or sensitivity case voltage violations reported for subarea A.

Subarea B – Waltham, Woburn and Lexington Area

The Waltham, Woburn and Lexington areas include 345 kV and 115 kV facilities that interconnect the stations between these three locations. There were a number of autotransformer and 115 kV line overloads and voltage violations for this area of the system. Overloads observed in this area were influenced by dispatch and transfer level conditions but were not a function of any specific set of conditions.

[redacted]

Figure 5-3 Subarea B N-1 Design (White) and Sensitivity (Shaded) Case Overload Elements

Worst Case Thermal Violations for Subarea B

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
B-2	Woburn Xfm	Woburn 345/115 kV autotransformer	Des	[redacted]	105	[redacted]	109
			Sen	None		None	

[redacted]

Overloads were not seen in the retirement sensitivity cases. The overloads are only seen in the cases with Mystic 9 in-service. Since all the retirement sensitivity cases have Mystic 9 OOS this overload was not observed in those cases.

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
B-3	533-508 Line	Lexington to Hartwell Ave 115 kV Line	Des	[redacted]	None	[redacted]	104
			Sen	None		None	

[redacted] The overload is only seen for the cases with [redacted] the violation is not seen in the retirement sensitivity cases.

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
						Contingency	% LTE
B-5	211-514 Line	Woburn to Mystic 115 kV Line	Des	[redacted]	195	[redacted]	204
			Sen	None		None	

[redacted]
The overloads are only seen in the cases with Mystic 9 in-service. Since all the retirement sensitivity cases have Mystic 9 OOS this overload was not observed in those cases. Loading above 152% LTE are also STE violations for this line.

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
B-6	282-520 / 282-521 Lines	Brighton to Watertown 115 kV line section	Des	[redacted]	128	[redacted]	131
			Sen	[redacted]	104	[redacted]	109
		Waltham to Watertown 115 kV line section (only 282-521 circuit)	Des	[redacted]	102	[redacted]	107
			Sen	[redacted]	115	[redacted]	115

The table above indicates the worst case contingency violation on different segments of the 282-520 and 282-521 lines for the design and sensitivity cases. Most contingency overloads on these lines can be mitigated through phase shifter adjustment. Some contingencies result in isolation of the phase shifters and in these cases there are no mitigating operator actions available. The worst case contingency that cannot be mitigated through operator action is for a [redacted]

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
B-8	346 / 365 Lines	Woburn to N. Cambridge 345 kV	Des	None		None	
			Sen	[redacted]	114	[redacted]	120
Loss of either 346 345 kV line from Woburn to N. Cambridge or the companion 365 345 kV line [redacted] This only occurs for retirement case scenarios.							

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
B-9	338 Line	Tewksbury to Woburn 345 kV	Des	None		None	
			Sen	None		[redacted]	102
[redacted] results in overload of the 338 line. This only occurs for the 2023 retirement case scenarios.							

Worst Case Low Voltage Violations for Subarea B

There were no design case or sensitivity low voltage violations reported for subarea B.

Worst Case High Voltage Violations for Subarea B

Table 5-8 Worst Design Case High Voltage Violations for Subarea B

Bus Name	Base kV	Contingency	Summer Off Peak	Min Load
Waltham	230	[redacted]	1.0554	N/A
Waltham	115	[redacted]	1.0733	N/A

Subarea C - Downtown Boston 115 kV Cables

Overloads for this segment of the Greater Boston area were in some cases (i.e. C-1, C-2, and C-3) associated with specific transfer levels of either high Boston Import or high North-South transfers. The 115 kV cables [redacted] were the most severely overloaded under certain dispatch conditions. The remaining overloads were observed across a wide range of transfer level and dispatch conditions.

[redacted]

Figure 5-4 Subarea C N-1 Design (White) and Sensitivity (Shaded) Case Overloaded Elements

Worst Case Thermal Violations for Subarea C

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
C-1	329-510/511	Mystic - Somerville 115 kV section	Des	[redacted]	109	[redacted]	113
			Sen	[redacted]	N/A	[redacted]	N/A
		Brighton – Somerville 115 kV section	Des	[redacted]	103	[redacted]	106
			Sen	[redacted]	106	[redacted]	109

The overloads from Mystic to Somerville overload for [redacted]. These overloads are only seen for the dispatches [redacted] are restricted to the design cases. However, for the segment between Brighton and Somerville overloads are observed for [redacted]. The overloads for the retirement cases are slightly higher than the overloads for the design cases.

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
C-3	385-511	High St. – K Street 115 kV section	Des	[redacted]	115	[redacted]	120
			Sen	[redacted]	120	[redacted]	126
		Kingston – High St. 115 kV section	Des	[redacted]	137	[redacted]	143
			Sen	[redacted]	142	[redacted]	149

The worst case overloads occur for [redacted]er. This overload can be mitigated for most contingencies by [redacted]. The worst case contingency that cannot be resolved through operator action is [redacted]

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
C-4	250-516/517	K Street - Chatham 115 kV section	Des	[redacted]	119	[redacted]	125
			Sen	[redacted]	135	[redacted]	142
		Mystic – Hawkins 115 kV section	Des	[redacted]	141	[redacted]	141
			Sen	None		None	

These lines overload for [redacted]. The overloads occurred for a number of design case dispatch conditions as well as for the retirement sensitivity cases. [redacted].

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
C-5	110-510/511	Baker St. – Washington St. 115 kV section	Des	[redacted]	120	[redacted]	113
			Sen	[redacted]	105	[redacted]	109
		Colburn – Washington St. 115 kV section	Des	[redacted]	101	[redacted]	102
			Sen	None		[redacted]	101
The loading on the 110-510/511 lines is [redacted]. These overloads are all below STE ratings and operator adjustment post contingency can correct them.							

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
C-7	324 or 372	Mystic – Kingston 345 kV cables	Des	[redacted]	115	[redacted]	116
			Sen	None		None	
[redacted]. The overloads only occurred for design cases with Mystic 9 out of service and with Mystic 7 and 8 in-service. This was not seen for the retirement cases since Mystic 7 and 8 are out of service.							

Worst Case Low Voltage Violations for Subarea C

There were no design case or sensitivity low voltage violations reported for subarea C.

Worst Case High Voltage Violations for Subarea C

Table 5-9 Worst Design Case High Voltage Violations for Subarea C

Bus Name	Base kV	Contingency	Summer Off Peak	Min Load
K Street	345	[redacted]	N/A	1.0556

Subarea D - Sudbury, Marlboro & Northborough Area

The Sudbury, Marlboro and Northborough area overloads were, for the most part, driven by isolating loads onto facilities with limited capacity. There was minimal sensitivity to the dispatch conditions modeled.

[redacted]

Figure 5-5 Subarea D N-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Worst Case Thermal Violations for Subarea D

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
D-1	W-23	Fitch Rd to Woodside 69 kV	Des	None		[redacted]	105
			Sen	None		[redacted]	104
This line overloads for [redacted].							

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
D-3	W-23W	Woodside to MWRA and MWRA to Northborough Road 69 kV line sections	Des	[redacted]	113	[redacted]	119
			Sen	[redacted]	113	[redacted]	117
This line overloads for [redacted] between Woodside and MWRA and between MWRA and Northborough Rd in conjunction with [redacted]. Loading above 104% of LTE are also a STE violation for this line.							

Worst Case Low Voltage Violations for Subarea D

Table 5-10 Worst Case Low Voltage Violations for Subarea D

Bus Name	Base kV	Contingency	2018 DES	2018 SEN	2023 DES	2023 SEN
Sudbury	115	[redacted]	0.9278	0.927	0.9146	None
		[redacted]	None	None	None	0.9116
Speen Street	115	[redacted]	None	None	None	0.9197
		[redacted]	0.9432	None	None	None
		[redacted]	None	0.9432	0.9301	None

Worst Case High Voltage Violations for Subarea D

Table 5-11 Worst Design Case High Voltage Violations for Subarea D

Bus Name	Base kV	Contingency	Summer Off Peak	Min Load
Sudbury	115	[redacted]	1.0697	N/A
Speen Street	115	[redacted]	1.0622	N/A

Subarea E - Holbrook and W. Walpole Area

The Holbrook and W. Walpole area overloads were primarily associated with dispatch conditions with Fore River running. These overloads are not mitigated through [redacted]

[redacted]

Figure 5-6 Subarea E N-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Worst Case Thermal Violations for Subarea E

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
E-1	447-508	Holbrook to S. Randolph 115 kV section	Des	[redacted]	108	[redacted]	111
			Sen	[redacted]	107	[redacted]	109
		Canton to S. Randolph 115 kV section	Des	None		[redacted]	101
			Sen	None		None	
These lines overload for a [redacted] This forces higher flows on 447-508 from the Holbrook end of the line. Loadings above 100% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
E-10	148-522XY	Dover to Needham 115 kV	Des	None		[redacted]	100+
			Sen	None		[redacted]	101

Under sensitivity retirement cases the line overloads [redacted] However, the loading is below STE and the overload can be mitigated by adjusting the Baker Street PS.

Worst Case Low Voltage Violations for Subarea E

There were no design case or sensitivity case low voltage violations reported for subarea E.

Worst Design Case High Voltage Violations for Subarea E

Table 5-12 Worst Design Case High Voltage Violations for Subarea E

Bus Name	Base kV	Contingency	Summer Off Peak	Min Load
Hyde Park	345	[redacted]	1.0552	1.0579
Stoughton	345	[redacted]	None	1.0562
West Medway	230	[redacted]	1.0578	None
Baker Street	115	[redacted]	1.0551	None

Subarea F - Boston, Golden Hills and Wakefield Junction Area

Golden Hills and Wakefield area overloads were observed for a number of contingency events and under a number of transfer level conditions.

[redacted]

Figure 5-7 Subarea F N-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Worst Case Thermal Violations for Subarea F

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
F-4	349 X/Y	Wakefield Junction – Mystic 345 kV cable	Des	None		None	
			Sen	[redacted]	105	[redacted]	108

This line overloads for [redacted]ne under retirement case scenarios.

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
F-6	Q-169	GE River to Lynn 115 kV line section	Des	None		[redacted]	100+
			Sen	None		[redacted]	104
		RESCO/Saugus to GE River 115 kV line section	Des	None		None	
			Sen	None		[redacted]	103

This line overloads due to [redacted] primarily under retirement case scenarios in 2023. Marginal overloads are seen for the design cases in 2023.

Table 5-13 Worst Case Low Voltage Violations for Subarea F

Bus Name	Base kV	Contingency	2018		2023	
			DES	SEN	DES	SEN
Chelsea	115	[redacted]	0.9178	0.9126	0.8974	0.8708

Worst Design Case High Voltage Violations for Subarea F

There were no design case high voltage violations reported for this subarea.

Subarea H – 115 kV Lines Near Tewksbury

Area H was primarily impacted by the unavailability of generation in the Boston RSP subarea under retirement sensitivity conditions.

[redacted]

Figure 5-8 Subareas H N-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Worst Case Thermal Violations for Subarea H

Ref	Element ID	Element Description		2018 Loading		2023 Loading	
				Contingency	% LTE	Contingency	% LTE
H-2	M-139 Line	Tewksbury to Billerica 115 kV line section	Des	None		[redacted]	101
			Sen	[redacted]	103	[redacted]	107
This line overloads for [redacted]. This line overloads under sensitivity retirement conditions for [redacted]							

Worst Case Low Voltage Violations for Subarea H

There were no design or sensitivity case low voltage violations reported for subarea H.

Worst Design Case High Voltage Violations for Subarea H

There were no design case high voltage violations reported for subarea H.

5.2.3 N-1-1 Thermal and Voltage Violation Summary

Initial element-out-of-service (N-1-1) testing included all 115 kV, 230 kV and 345 kV transmission lines as well as 345 kV autotransformers in the Greater Boston area that are considered Bulk Electric System ("BES") elements. These element-out-of-service conditions were tested against the full set of contingencies used in the N-1 tests. These were tested for design cases and for retirement sensitivity cases that modeled retirement of Mystic Unit 7. Testing of the system included use of an analytical tool that used a re-dispatch of New England generation, back-down of Boston RSP subarea generation and adjustment of the Boston RSP subarea phase shifters in an attempt to avoid overloads. These cases were evaluated using LTE ratings as they represented post-contingency, post-system adjustment conditions. Additionally, testing included evaluation of post-second contingency phase shifter adjustments, HVDC terminal adjustments and fast start unit back-down to mitigate each specific contingency pair where operator intervention was viable (i.e. overloads do not exceed STE ratings). Those contingencies that resulted in STE violations show the percentage of STE ratings and are indicated by noting "STE" after the overload percentage values.

Testing was also performed to assess the impact of possible generation retirement sensitivities on the element-out-of-service condition of the system. Mystic Unit 7 retirement was tested for N-1-1 conditions. Each of the retirement sensitivity cases included an assumption that Mystic 8 and 9 were unavailable. The results of thermal violations that were not seen in any other analysis are included in each area section described below.

Cases where overload conditions were found to exist that were unique to N-1-1 contingencies or had higher loading under N-1-1 conditions are reported by subarea below. This includes summary tables for design and retirement sensitivity cases. The list of the element-out-of-service conditions that were tested can be found in Table 12-2 included in Appendix F. The full results of thermal violations can be found in Appendix G.

Subarea A - 345 kV and 115 kV Northern Ties to Greater Boston

[redacted]

Figure 5-9 Subarea A N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-2	337	Sandy Pond – Tewksbury 345 kV	Mystic 7	[redacted]	DES	<100%	109
			[redacted]	[redacted]	SEN	115	122

This line overloads for [redacted]. The [redacted] as it would see overload conditions for the first contingency and this action further aggravates the overload condition on the 337 line. Loadings above 107% LTE are also STE violations for this line. Note that even though there are no overloads reported for the 2018 load level for the design cases, the line depends on generation rejection with [redacted] to avoid STE overloads in 2018. [redacted].

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-3	394	Seabrook – Ward Hill 345 kV	[redacted]	[redacted]	DES	105	107
			[redacted]	[redacted]	SEN	108	113

This line overloads for loss of resource in Boston or loss of import capability into Boston followed by [redacted]. For the 2023 retirement case the worst case condition is different. [redacted]. Loadings above 100% LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-5	Sandy Pond Auto	Sandy Pond 345 kV to 115 kV autotransformer #1	[redacted]	[redacted]	DES	133	136
			[redacted]	[redacted]	SEN	140	140

The Sandy Pond Auto #1 overloads for [redacted] Loadings above 127% LTE are also STE violations and [redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-8	A-253	Dunbarton Tap to Merrimack 230 kV	[redacted]	[redacted]	DES	118	124
			[redacted]	[redacted]	SEN	112	113

The 230 kV line from Merrimack to Dunbarton Tap overloads for loss of the [redacted] For the National Grid portion of the line loadings above 106% LTE are also STE violations. For the NU portion of the lines loadings above 100% LTE are also STE violations. The [redacted] sensitivity cases have lower violations than the design cases since all the retirement sensitivity cases have Phase II in-service. The worst case loadings for the design cases are seen with [redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-9	B-202S	Dunbarton Tap to North Litchfield 230 kV	[redacted]	[redacted]	DES	108	113
			N/A	N/A	SEN	None	None

The 230 kV line from Dunbarton Tap to North Litchfield overloads for [redacted]. For the NATIONAL GRID portion of the lines loadings above 106% LTE are also STE violations. For the NU portion of the lines loadings above 100% LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-10	I-135	Fitzwilliam to Flagg Pond (NU section)	[redacted]	[redacted]	DES	101	107
			N/A	N/A	SEN	None	None

The initial segment of the I-135 line from Fitzwilliam to Flagg Pond overloads for [redacted] This only occurs for [redacted]. Since the Mystic 7 retirement sensitivities have Phase 2 in-service, we do not see this overload. Loadings above 100% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-13	N-214	N. Litchfield to Tewksbury 230 kV	[redacted]	[redacted]	DES	None	111
			N/A	N/A	SEN	None	None

The 230 kV line from N. Litchfield to Tewksbury overloads for [redacted] Since the Mystic 7 retirement sensitivities have Phase 2 in-service, we do not see this overload. Loadings above 109% of LTE are also STE violations for this line.

Worst Case Low Voltage Violations for Subarea A

There were no design case low voltage violations reported for subarea A.

Table 5-14 Worst Case Low Voltage Violations for Subarea A

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Tewksbury	115	[redacted]	[redacted]	None	None	None	0.9405
West Amesbury	115	[redacted]	[redacted]	None	None	None	0.9354

Worst Case High Voltage Violations for Subarea A

Table 5-15 Worst Design Case High Voltage Violations for Subarea A

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Tewksbury	345	[redacted]	[redacted]	None	1.0698
Ward Hill	345	[redacted]	[redacted]	None	1.0618
	115	[redacted]	[redacted]	None	1.0593
West Amesbury	345	[redacted]	[redacted]	None	1.0569
	115	[redacted]	[redacted]	None	1.0574

Subarea B – Waltham, Woburn and Lexington Area

[redacted]

Figure 5-10 Subarea B N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-1	391-508	Burlington - Hartwell 115 kV line	[redacted]	[redacted]	DES	112	124
			N/A	N/A	SEN	None	None

Loss of the [redacted] followed by loss of [redacted] overloads this line. Flows over 115 kV lines into [redacted] are increased as flows from [redacted] line are increased due [redacted] resulting in the overload of this line. These conditions occur when [redacted] is in service and [redacted] is opened. Since Mystic 9 is out of service for the Mystic 7 retirement sensitivity cases this line does not overload for those cases. Loadings above 100% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-2	Woburn Xfmr	Woburn 345/115 kV autotransformer	[redacted]	[redacted]	DES	150	158
			[redacted]	[redacted]	SEN	108	111

Loss of the [redacted] fault overloads this transformer. Flows into [redacted] bus are increased as flows from [redacted] line are increased due t[redacted] resulting in the overload of this line. These conditions occur when [redacted] in service and the [redacted] [redacted] is opened. Loadings above 127% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-3	533-508	Lexington – Hartwell 115 kV	[redacted]	[redacted]	DES	152	167
			[redacted]	[redacted]e	SEN	None	100+

Loss of [redacted] followed by loss of [redacted]r fault overloads this line. Flows over 115 kV lines into [redacted] are increased as flows from [redacted] line are increased due to [redacted] resulting in the overload of this line. Loading above 100% of LTE are also STE violations for this line.

For the [redacted] sensitivities the line only overloads for the 2023 conditions with [redacted] as the first contingency followed by the loss of [redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-5	211-514	Woburn - Mystic 115 kV	[redacted]	[redacted]	DES	266	277
			[redacted]	[redacted]	SEN	156	165

The 211-514 Woburn to Mystic 115 kV cable overloads for loss of a number of initial contingencies (worst case was [redacted] followed by loss of [redacted] fault. Flows over this cable can be mitigated in many cases by [redacted] There are cases where Mystic 9 is running and due to short circuit constraints the bus tie cannot be closed therefore overloads are still present. For retirement sensitivity cases loss of [redacted] followed by loss of [redacted] results in overloads and these cannot be mitigated through operator actions. Loadings above 152% of LTE are also STE violations for this line.

For the Mystic 7 retirement sensitivities the highest overloads are seen with [redacted] as the first contingency followed by [redacted].

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-6	282-520 / 282-521 (segment #1)	Brighton - Watertown 115 kV cable section	[redacted]	[redacted]	DES	204	216
			[redacted]	[redacted]	SEN	185	199
	282-520 / 282-521 (segment #2)	Watertown to Waltham 115 kV cable section	[redacted]	[redacted]	DES	185	185
			[redacted]	[redacted]	SEN	184	203

The Brighton to Watertown section of the 282-520/521 cables occurs for conditions when [redacted]. For the segments from Waltham to Watertown the highest overloads are seen with [redacted]. Loadings above 155% of LTE are also STE violations for these cables.

There are a number of additional overloads reported that can be corrected through operator adjustment of [redacted].

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-7	358	Mystic to North Cambridge 345 kV	[redacted]	[redacted]	DES	141	146
			[redacted]	[redacted]	SEN	131	139
	351	Mystic to North Cambridge 345 kV	[redacted]	[redacted]	DES	118	122
			[redacted]	[redacted]	SEN	116	123

These lines overload for loss of the [redacted] followed by [redacted].

Under retirement scenario conditions the [redacted] overloads for loss of the [redacted]ollowed by loss of [redacted]. The 358 line overloads for loss of the [redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-8	346/365	North Cambridge – Woburn 345 kV	[redacted]	[redacted]	DES	151	151
			[redacted]	[redacted]	SEN	203	214

These lines overload with [redacted]V out of service followed by a single contingency that removes either the [redacted]. Loadings above 178% of LTE are also STE violations for these cables.

Retirement scenario conditions resulted in STE violations for these cables.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-9	338	Tewksbury – Woburn 345 kV	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	None	106
This line has the highest overload for [redacted] out of service followed by [redacted] The overload was only seen for the 2023 retirement sensitivity cases.							

Table 5-16 Worst Case Low Voltage Violations for Subarea B

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Woburn	**345**	[redacted]	[redacted]	None	None	None	0.7957
	115	[redacted]	[redacted]	None	None	None	0.9472
		[redacted]	[redacted]	None	None	0.9346	None
Lexington	**345**	[redacted]	[redacted]	None	None	None	0.7951
		[redacted]	[redacted]	None	None	0.9403	0.9118
	115	[redacted]	[redacted]	None	None	None	0.7889
Burlington MA	**115**	[redacted]	Woburn #106 [redacted]	None	None	None	0.7892
		[redacted]	[redacted]	0.9219	0.9303	0.9025	0.9151
		[redacted]	[redacted]	0.9240	0.9436	0.9084	0.9240
Hartwell	**115**	[redacted]	[redacted]	None	None	None	0.7892
		[redacted]	[redacted]	0.9219	0.9303	0.9025	0.9151
		[redacted]	[redacted]	0.9171	0.9375	0.9002	0.9165
Trapelo Road	**115**	[redacted]	[redacted]	None	None	None	0.7876
Waltham	[redacted]	[redacted]	[redacted]	None	None	0.9362	None

			[redacted]				
		[redacted]	[redacted]	None	0.9439	None	0.9292
		[redacted]	[redacted]	None	None	None	0.8322
	115	[redacted]	[redacted]	0.9246	None	0.8966	None
		[redacted]	[redacted]	None	0.9419	None	0.9217
		[redacted]	[redacted]	None	None	None	0.7916
Watertown	115	[redacted]	[redacted]	None	None	None	0.7927

Table 5-17 Worst Design Case High Voltage Violations for Subarea B

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Woburn	345	[redacted]	[redacted]		1.0728
Waltham	230	[redacted]	[redacted]	1.0729	
	115	[redacted]	[redacted]	1.0614	
			[redacted]		1.0586
Lexington	345	[redacted]	[redacted]		1.0686
	115	[redacted]	[redacted]	1.0553	
			[redacted]		1.0552
Trapelo Road	115	[redacted]	[redacted]	1.0573	
			[redacted]		1.0567
Watertown	115	[redacted]	[redacted]	1.0623	
			[redacted]		1.0596

Subarea C - Downtown Boston 115 kV Cables

[redacted]

Figure 5-11 Subarea C N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Thermal Violations for Subarea C

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-1	329-510/511 (Section #1)	Mystic – Somerville section of the 115 kV Cables	[redacted]	[redacted]	DES	126	144
			[redacted]	[redacted]	SEN	<100	109
	329-510/511 (Section #1)	Brighton – Somerville section of the 115 kV Cables	[redacted]	[redacted]	DES	127	127
			[redacted]	[redacted]	SEN	123	138
The Somerville to Mystic segment of these cables overload for [redacted]							

followed by [redacted] The section from Brighton to Somerville overloads for [redacted] followed by the loss of [redacted]

Under retirement sensitivity case conditions loss of [redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-2	329-512/513	Kingston – Brighton 115 kV Cables	[redacted]	[redacted]	DES	121	126
			[redacted]	[redacted]	SEN	106	108

These lines overload for loss of [redacted]. For design cases loss of [redacted]. Under retirement case scenarios loss of [redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-3	385-510	Kingston – K Street 115 kV Cables	[redacted]	[redacted]	DES	113	123
			[redacted]	[redacted]	SEN	115	125
	385-511		[redacted]	[redacted]	DES	162	168
			[redacted]	[redacted]	SEN	158	171

The worst case overloads on the 385-510 line occur for loss of [redacted]. The overloads are typically [redacted]. The highest overloads for the design cases are seen for the loss of [redacted]. For the retirement cases the [redacted]

The worst case overloads on the 385-511 line occur for the loss of [redacted]. These overloads are typically from [redacted] with the worst case second contingency being the loss of [redacted] For design cases loss of [redacted] followed by [redacted] overloads the 385-510. Under retirement case scenarios loss of [redacted] overloads the 385-511 line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-3	385-513	Kingston – K Street 115 kV Cables	[redacted]	[redacted]	DES	143	146
			[redacted]	[redacted]	SEN	101	102

This line overloads for loss of [redacted] followed by a [redacted]. The worst case design overloads occur for the dispatches with Mystic 9 out of service, and since all the retirement sensitivity cases have Mystic 9 in-service the retirement sensitivity overloads are lower than the design cases.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-4	250-516/517	Mystic – K Street 115 kV Cables	[redacted]	[redacted]	DES	136	141
			[redacted]	[redacted]	SEN	161	169

Under design conditions these lines overload for loss of [redacted] These overloads occur when [redacted] is out of service and [redacted]. It may be possible to mitigate the overload by [redacted]. However this action may introduce other overloads.

Under retirement scenario conditions loss of [redacted] results in the highest overload for the 250-516 cable in 2023. For 2018 the worst case overload is for the loss o[redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-5	110-510/511	Washington St. Tap to Baker St.115 kV cable section	[redacted]	[redacted]	DES	141	148
			[redacted]	[redacted]	SEN	195	188
		Washington Tap to Brighton 115 kV cable section	[redacted]	[redacted]	DES	104	119
			[redacted]	[redacted]	SEN	150	152
		Washington tap to Colburn 115 kV cable section	[redacted]	[redacted]	DES	132	145
			[redacted]	[redacted]	SEN	102	108
	514-510/511	Colburn to Kingston 115 kV cable section (514-510/511)	[redacted]	[redacted]	DES	138	143
			[redacted]	[redacted]	SEN	None	105

The flow on these cables is controlled by [redacted] and overloads that do not exceed STE rating can be mitigated through operator action. Loadings above 157% of LTE are also STE violations for these cables. However, all the violations above take phase shifter action into consideration and report the violations that are still observed after Phase shifter adjustments.

Loss of [redacted] result in the highest overloads under design case conditions on the Washington Street tap to Baker Street section. Loss of [redacted] results in the highest overload of these cables under retirement sensitivity case conditions. The retirement scenario conditions result in STE violations for these lines and phase shifter adjustment would not be an operational alternative to correct this loading.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-7	324 / 372	Mystic to Kingston 345 kV	[redacted]	[redacted]	DES	117	119
			N/A	N/A	SEN	None	None

Loss of [redacted] results in overload of these cables. These overloads occur when [redacted] is out of service and the [redacted]. Since both Mystic7 and 8 are out of service for the Mystic 7 retirement sensitivity cases, these overloads are not observed.

Ref	Element ID	Element Description	Element Out of Service	Continge[redacted]		2018 Loading	2023 Loading
C-8	329-530/531	Brighton to N. Cambridge 115 kV	[redacted]	[redacted]	DES	129	135
			N/A	N/A	SEN	None	None

Loss of [redacted] isolates all N. Cambridge load on the single remaining 115 kV circuit. The overload only occurs for cases [redacted] is unavailable and hence is not seen for the retirement sensitivity since all the retirement sensitivity cases have [redacted] in-service.

Table 5-18 Worst Case Low Voltage Violations for Subarea C

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Brighton	115	[redacted]	[redacted]	None	None	None	0.7958
Somerville	115	[redacted]	[redacted]	None	None	None	0.7986
Kingston	345	[redacted]	[redacted]	None	None	None	0.7974
	115	[redacted]	[redacted]	None	None	None	0.7992
Carver	115	[redacted]	[redacted]	None	None	None	0.7975
Scotia Street	115	[redacted]	[redacted]	None	None	None	0.7957

			[redacted]				
High Street	115	[redacted]	[redacted]	None	None	None	0.7995
K Street	345	[redacted]	[redacted]	None	None	None	0.9417
	115	[redacted]	[redacted]	None	None	None	0.8017
Mystic	345	[redacted]	[redacted]	None	None	None	0.7974
	115	[redacted]	[redacted]	None	None	None	0.8023
		[redacted]	[redacted]	None	None	0.9188	None
Chatham	115	[redacted]	[redacted]	None	None	None	0.8036
Hawkins	115	[redacted]	[redacted]	None	None	None	0.8030
Colburn	115	[redacted]	[redacted]	None	None	None	0.7956
North Cambridge	345	[redacted]	[redacted]	None	None	None	0.7969
	115	[redacted]	[redacted]	None	None	None	0.7953

Table 5-19 Worst Design Case High Voltage Violations for Subarea C

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Mystic	345	[redacted]	[redacted]		1.0751
	115	[redacted]	[redacted]	1.0591	
		[redacted]	[redacted]		1.0571
Brighton	115	[redacted]	[redacted]	1.062	
		[redacted]	[redacted]		1.0593
K Street	345	[redacted]	[redacted]	1.0832	
	345	[redacted]	[redacted]		1.0861
	115	[redacted]	[redacted]	1.0652	
	115	[redacted]	[redacted]		1.0627
Chatham	115	[redacted]	[redacted]	1.0605	

		[redacted]	[redacted]		1.0577
Colburn	**115**	[redacted]	[redacted]		1.0606
		[redacted]	[redacted]	1.0632	
Hawkins	**115**	[redacted]	[redacted]	1.0601	
		[redacted]	[redacted]		1.0576
High Street	**115**	[redacted]	[redacted]	1.0644	
		[redacted]	[redacted]		1.0617
Kingston	**345**	[redacted]	[redacted]		1.0749
Carver Street	**115**	[redacted]	[redacted]	1.0638	
		[redacted]	[redacted]		1.0611
Kingston	**115**	[redacted]	[redacted]	1.0642	
		[redacted]	[redacted]		1.0615
North Cambridge	**345**	[redacted]	[redacted]		1.0745
	115	[redacted]	[redacted]		1.058
			[redacted]	1.0648	
Scotia Street	**115**	[redacted]	[redacted]		1.0602
		[redacted]	[redacted]	1.063	
Somerville	**115**	[redacted]	[redacted]	1.06	
		[redacted]	[redacted]		1.0578

Subarea D - Sudbury, Marlboro and Northborough Area

[redacted]

Figure 5-12 Subarea D N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Thermal Violations for Subarea D

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-1	W-23	Fitch Rd - Woodside 69 kV	[redacted]	[redacted]	DES	213	213
			[redacted]	[redacted]	SEN	212	212

Loss of [redacted] overloads on the W-23 69 kV line. Loadings above 108% of LTE are also STE violations for this line.

An important consideration for this event is the severity of the overload. Loss of [redacted].

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-2	E-157	Millbury - Northboro Rd 115 kV	[redacted]	[redacted]	DES	131	136
			[redacted]	[redacted]	SEN	130	136

Loss of [redacted] results in overloads on the E-157 115 kV line. Loadings above 106% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-3	W-23W	Northboro Rd - Woodside 69 kV	[redacted]	[redacted]	DES	265	265
			[redacted]	[redacted]	SEN	264	264

Loss of [redacted] results in overloads on the W-23W kV line. Loadings above 104% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-4	X-24	North Grafton – Westboro 69 kV	[redacted]	[redacted]	DES	184	185
			[redacted]	[redacted]	SEN	181	183

Loss of [redacted] results in overloads on this line. Loadings above 108% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-5	433-507	Framingham – Speen St. 115 kV	[redacted]	[redacted]	DES	136	137

				[redacted]r			
			[redacted]	[redacted]	SEN	137	137

Loss of [redacted] results in overloads on this line. Flows into Boston RSP subarea are seen on this line and loss of [redacted] supply into Boston RSP subarea results in overloading of the this line. Loadings above 100% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-6	282-507	Waltham - Sudbury 115 kV	[redacted]	[redacted]	DES	105	110
			[redacted]	[redacted]	SEN	106	112

Loss of [redacted] overloads the 282-507 Waltham to Sudbury 115 kV line due to the increased loading from [redacted] Loadings above 100% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-7	240-508	Sherborn - Framingham 115 kV	[redacted]	[redacted]	DES	108	108
			[redacted]	[redacted]	SEN	102	110

Loss of [redacted] results in overloads on the 240-508 115 kV line. [redacted]. In 2023 under retirement sensitivity case conditions or loss of [redacted] is more severe than [redacted] Loadings above 100% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-7	274-509	Medway -	[redacted]	[redacted]	DES	101	106

		Sherborn 115 kV	[redacted]	[redacted]			
			[redacted]	[redacted]	SEN	None	110

Loss of [redacted] results in overloads on the 274-509 115 kV line. Loadings above 100% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-7	455-507	Sherborn – W. Framingham 115 kV	[redacted]	[redacted]	DES	132	137
			[redacted]	[redacted]	SEN	132	137

Loss of [redacted] results in overloads on the 455-507 115 kV line. Loadings above 100% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-7	513-507	Northboro Rd – W. Framingham 115 kV	[redacted]	[redacted]	DES	115	120
			[redacted]	[redacted]	SEN	115	121

Loss of [redacted] results in overloads on the 513-507 (connecting to D-156 on the NATIONAL GRID system) 115 kV line. Loadings above 100% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-9	N-40 A&B	Fitch Rd. to Pratts Junction 69 kV	[redacted]	[redacted]	DES	126	127
			[redacted]	[redacted]	SEN	125	126

Loss of [redacted] line results in overloads on the N-40 A&B 69 V line. Loadings above 108% of LTE are also STE violations for this line.

Table 5-20 Worst Case Low Voltage Violations for Subarea D

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Woodside	69	[redacted]	[redacted]	0.6032	0.6047	0.5939	None
Northboro Road	69	[redacted]	[redacted]	0.5445	0.5458	0.5321	None
	69	[redacted]	[redacted]	None	None	0.8971	None
MWRA	69	[redacted]	[redacted]	0.5574	0.5587	0.5459	None
North Grafton	69	[redacted]	[redacted]	0.8017	0.8019	0.7925	None
Westboro	69	[redacted]	[redacted]	0.5445	0.5458	0.5321	None
Framingham	230	[redacted]	[redacted]	None	None	None	0.9280
	115	[redacted]	[redacted]	0.9423	0.9347	0.9302	0.9087
	115	[redacted]	[redacted]	None	None	None	0.8951
Sherborn	115	[redacted]	[redacted]	None	None	None	0.9037
West Framingham	115	[redacted]	[redacted]	None	None	None	0.9245
Sudbury	115	[redacted]	[redacted]	0.8703	None	0.8335	None
	115	[redacted]	[redacted]B	0.9288	0.8917	0.8940	0.8695
	115	[redacted]	[redacted]	None	None	None	0.8126
Speen Street	115	[redacted]	[redacted]	0.8579	None	0.8212	None
	115	[redacted]	[redacted]B	0.9177	0.8796	0.8814	0.8566
	115	[redacted]	[redacted]	None	None	None	0.8365

Table 5-21 Worst Design Case High Voltage Violations for Subarea D

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Sudbury	115	[redacted]	[redacted]	1.1145	1.0686
Framingham	115	[redacted]	[redacted]	1.0594	
Speen Street	115	[redacted]	[redacted]	1.1135	1.0677

Subarea E - Holbrook and W. Walpole Area

[redacted]

Figure 5-13 Subarea E N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Thermal Violations for Subarea E

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-1	447-508/509	Holbrook – W. Walpole 115 kV	[redacted]	[redacted]	DES	118	125
			[redacted]	[redacted]	SEN	114	127

Loss of [redacted] overloads this line. The overload on this section of the line only occurs when Fore River generation in unavailable. Under retirement sensitivity case conditions loss of [redacted] overloads the Holbrook end of this line. Loadings above 100% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-4	K Street autotransformers	K Street 345 kV to 115 kV autotransformer #1 & #2	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	120	121

Loss of [redacted] results in overloads for these autotransformers in 2023. A different second contingency has the highest overloads for 2018 but both contingencies involve the loss of [redacted] The overloads only occur for the retirement scenario cases. Loss of [redacted] also overloads the autotransformers. Loadings above 110% of LTE are also STE violations for these transformers.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-4	3161	W. Walpole to Stoughton 345 kV	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	102	103

The loss of [redacted] overloads the 3161 line under retirement sensitivity case conditions.

The combined loss of two northern import paths into Boston RSP subarea results in the overload of the southern lines which supply imports to Boston RSP subarea via [redacted] Other initial line out conditions that show overloads to a lesser degree include [redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-4	3162	Stoughton to K Street 345 kV	[redacted]	[redacted]	DES	None	101
			[redacted]	[redacted]	SEN	144	144

The loss of the [redacted] overloads the 3161 line.

The combined loss of two northern import paths into Boston RSP subarea results in the overload of the southern lines which supply imports to Boston RSP subarea via [redacted].

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-4	3163	Stoughton to K Street 345 kV	[redacted]	[redacted]	DES	None	102
			[redacted]	[redacted]	SEN	146	146

The loss of [redacted] overloads the 3163 line.

The combined loss of two northern import paths into Boston RSP subarea results in the overload of the southern lines which supply imports to Boston RSP subarea via [redacted].

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-5	Hyde Park autotransformer	Hyde Park 345 kV autotransformer #1	[redacted]	[redacted]	DES	107	108
			[redacted]	[redacted]	SEN	None	105

Loss of [redacted] result in overload of the Hyde Park autotransformer. Under retirement sensitivity case conditions loss of [redacted] also results on overload of these transformers. Loadings greater than 100% of LTE are also STE violations.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-6	282-602	W. Medway – Waltham 230 kV line	[redacted]	[redacted]	DES	None	104
					SEN	116	116

Loss of [redacted] results in an overload for this line.

The combined loss of two import northern paths into Boston RSP subarea results in the overload of the all major import lines coming from the south.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-6	456-522	W. Walpole to Dover 115 kV line	[redacted]	[redacted]	DES	None	None
					SEN	None	103

Loss of [redacted] results in an overload for this line under retirement sensitivity conditions. Loadings above 100% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-10	148-522XY	Dover to Needham 115 kV line	[redacted]	[redacted]	DES	None	112
			[redacted]	[redacted]	SEN	116	118

Loss of [redacted] overloads this line under design case conditions. Under retirement sensitivity case conditions loss of [redacted] overloads this line. However, the loadings are below STE and the overload can be mitigated by [redacted].

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-14	W. Medway 345A autotransformer	W. Medway 345 kV to 230 kV autotransformer	[redacted]	[redacted]	DES	None	None
					SEN	109	108

Loss of [redacted] overloads this autotransformer.

The combined loss of two import northern paths into Boston RSP subarea results in the overload of the all major import lines coming from the south. This overload is only observed for the retirement cases.

Table 5-22 Worst Case Low Voltage Violations for Subarea E

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Norwood	115	[redacted]	[redacted]	None	None	None	0.9424
Walpole	115	[redacted]	[redacted]	None	None	None	0.9325
Baker Street	115	[redacted]	[redacted]	None	None	None	0.8080
Needham	115	[redacted]	[redacted]	None	None	None	0.8630
Medway	115	[redacted]	[redacted]	None	None	None	0.9334
Rocky Hill	115	[redacted]	[redacted]	None	None	None	0.9419
Hyde Park	115	[redacted]	[redacted]	None	0.9407	0.9398	0.8983
	115	[redacted]	[redacted]	None	None	None	0.8560
Dover	115	[redacted]	[redacted]	None	None	None	0.8936

Table 5-23 Worst Design Case High Voltage Violations for Subarea E

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Edgar	115	[redacted]	[redacted]		1.0604
Needham	115	[redacted]	[redacted]	1.0614	1.0617
Dover MA	115	[redacted]	[redacted]	1.0587	1.0588
Holbrook	345	[redacted]	[redacted]	1.0679	1.0789
	115	[redacted]	[redacted]		1.0632
Hyde Park	345	[redacted]	[redacted]	1.0867	
		[redacted]	[redacted]		1.0848
	115	[redacted]	[redacted]	1.0647	
		[redacted]	[redacted]		1.0663

Stoughton	**345**	[redacted]	[redacted]	1.0852	
		[redacted]	[redacted]		1.0835
Baker Street	**115**	[redacted]	[redacted]	1.0634	
		[redacted]	[redacted]		1.0648
Canton	**115**	[redacted]	[redacted]		1.0569
West Medway	**230**	[redacted]	[redacted]	1.0572	
East Weymouth	**115**	[redacted]	[redacted]		1.0607
Norwood	**115**	[redacted]	[redacted]		1.0569
South Randolph	**115**	[redacted]	[redacted]		1.0615
West Walpole	**345**	[redacted]	[redacted]		1.0554

Subarea F - Boston, Golden Hills and Wakefield Junction Area

[redacted]

Figure 5-14 Subarea F N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Thermal Violations for Subarea F

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
F-1	F-158N	Wakefield Junction – Maplewood 115 kV	[redacted]	[redacted]	DES	150	154
			[redacted]	[redacted]	SEN	182	208

Loss of [redacted]023 results in an overload of this line. Under retirement sensitivity case conditions loss of [redacted] line also overload this line. Loadings above 106% of LTE are also STE violations.

Under this outage scenario a significant amount of the flows on [redacted] will show up on the 115 kV lines feeding into the North Shore 115 kV system through [redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
F-2	F-158S	Maplewood – Everett 115 kV	[redacted]	[redacted]	DES	132	135
			[redacted]	[redacted]	SEN	162	184

Loss of [redacted] results in overloads of this line under design case conditions. Loadings above 107% of LTE are also STE violations.

Loss of [redacted] ble results in an overload of this line under retirement sensitivity case conditions.

Under this outage scenario a significant amount of the Boston imports from [redacted] is fed into the North Shore 115 kV system [redacted]. Substation. Loadings above 106% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
F-4	349 X/Y	Wakefield Junction – Mystic 345 kV Cables	[redacted]	[redacted]	DES	None	105
			[redacted]	[redacted]	SEN	113	123

Loss of [redacted] results in an overload of this line. Loadings above 123% of LTE are also STE violations.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
F-6	Q-169 (Section 2 in 2018) (section 3 in 2023)	Wakefield Junction – Lynn 115 kV line (Resco – Lynn section)	[redacted]	[redacted]	DES	110	116
			[redacted]	[redacted]	SEN	110	117

Loss of [redacted] results in an overload of this line under design case conditions and under 2018 retirement sensitivity case conditions. Under retirement sensitivity case conditions in 2023 loss of [redacted] result in overload of this line. Loadings above 105% of LTE are also STE violations.

Table 5-24 Worst Case Low Voltage Violations for Subarea F

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Golden Hills	115	[redacted]	[redacted]	None	None	None	0.8884
Wakefield Junction	115	[redacted]	[redacted]	None	None	None	0.9217
Melrose	115	[redacted]	[redacted]	None	None	None	0.8904
Maplewood	115	[redacted]	[redacted]	None	None	None	0.8350
Chelsea	115	[redacted]	[redacted]	0.8660	None	0.8509	0.8421
	115	[redacted]	[redacted]	None	None	None	0.8005
Revere	115	[redacted]	[redacted]	0.8742	None	0.8596	0.8507
	115	[redacted]	[redacted]	None	None	None	0.8053
Resco Saugus	115	[redacted]	[redacted]	None	None	None	0.8465
GE River	115	[redacted]	[redacted]	0.8983	None	0.8859	0.8770
	115	[redacted]	[redacted]	None	None	None	0.8214
Lynn	115	[redacted]	[redacted]	None	None	0.8975	0.8886
	115	[redacted]	[redacted]	None	None	None	0.8298

Table 5-25 Worst Design Case High Voltage Violations for Subarea F

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Everett	115	[redacted]	[redacted]	1.0566	
		[redacted]	[redacted]		1.0575
Lynn	115	[redacted]	[redacted]		1.0564
Maplewood	115	[redacted]	[redacted]		1.0593
Wakefield	115	[redacted]	[redacted] B		1.0649
Golden Hills	115	[redacted]	[redacted]		1.0639

Melrose	**115**	[redacted]	[redacted]	1.0639
Wakefield Junction	**345**	[redacted]	[redacted]	1.0746
	115	[redacted]	[redacted]	1.0664
GE River	**115**	[redacted]	[redacted] tor	1.0553
Resco-Saugus	**115**	[redacted]	[redacted]	1.0585

Subarea H – 115 kV Lines Near Tewksbury

[redacted]

Figure 5-15 Subarea H N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Thermal Violations for Subarea H

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-1	S-145E/T-146E	Railyard – Salem Harbor 115 kV	[redacted]	[redacted]	DES	129	129
			[redacted]	[redacted]	SEN	138	148
Loss of [redacted] es results in overload of the companion line. Reducing [redacted] prior to the second contingency would resolve this overload. This will not be treated as a need.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-1	S-145W/T-146W	N. Reading – Wakefield Junction. 115 kV	[redacted]	[redacted]	DES	117	129
			[redacted]	[redacted]	SEN	120	119
Loss of [redacted] results in overload of these lines in design cases. Under retirement sensitivity case conditions loss of [redacted] results in overloads on these lines. The design case overloads only							

occur for [redacted] out of service. Loadings above 102% of LTE are also STE violations.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-1	T-146	E. Tewksbury - Tewksbury 115 kV	[redacted]	[redacted]	DES	104	110
					SEN	None	None

Loss of [redacted] results in overload of these lines in design cases. The design case overloads only occur for [redacted] out of service. Loadings above 109% of LTE are also STE violations.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-2	M-139	Tewksbury – Pinehurst 115 kV	[redacted]	[redacted]	DES	121	127
			[redacted]	[redacted]	SEN	131	152
		Pinehurst – N. Woburn Tap 115 kV line section	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	101	124

Loss of [redacted] result in overloads for this line. Under retirement sensitivity case conditions for 2018 or loss of [redacted] result in overloads for this line. Loadings above 106% of LTE are also STE violations for this line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-3	N-140 (211-504)	Tewksbury – Pinehurst 115 kV line section	[redacted]	[redacted]	DES	110	114
			[redacted]	[redacted]	SEN	115	135
		Pinehurst – N. Woburn Tap 115 kV line section	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	110	129

Loss of [redacted] results in overload of this line. The next section of this line also overloads for [redacted] under retirement sensitivity case conditions. Loadings above 106% of LTE are also STE violations.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-5	K-137E/L138E	Sandy Pond to Littleton 115 kV line	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	116	116

Loss of [redacted] results in overloads on this line under retirement case scenario conditions. The loadings on K137E are around 116% and the loadings on the L138E are about 101%.

Table 5-26 Worst Case Low Voltage Violations for Subarea H

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Pinehurst	115	[redacted]	[redacted]	None	None	None	0.8718

Table 5-27 Worst Design Case High Voltage Violations for Subarea H

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
King Street	115	[redacted]	[redacted]	1.0575	None
West Salem	115	[redacted]	[redacted]	1.0673	1.0575
Railyard	115	[redacted]	[redacted]B	1.0677	1.0564
Bartholomew	115	[redacted]	[redacted]B	1.0669	1.0593
Ipswich River	115	[redacted]	[redacted]	1.0629	1.0649
Middleton	115	[redacted]	[redacted]	1.0617	1.0639
South Danvers	115	[redacted]	[redacted]	1.0656	1.0639
Salem Harbor	115	[redacted]	[redacted]B	1.0677	1.0746
Woodchuck Hill	115	[redacted]	[redacted]	1.0607	1.0664

N-1/N-1-1 Load Isolation Conditions

There were a set of events that were noted as causing consequential load loss approaching or exceeding 300 MW of customer load. These are load pockets within the system that are only served by two transmission lines and the loss of both lines disconnects the load from the system. The following load pockets were identified in the Greater Boston area:

N-1 Load Interruption

- Norwood/Canton/South Randolph Load Pocket (within Subarea E)
    - Loss of [redacted] disconnects 313 MW of load in 2018 growing to 324 MW of load in 2023 (Due [redacted]

N-1-1 Load Interruption

- Sudbury Load Pocket (within Subarea D)
    - Loss of [redacted] disconnects 290 MW of load in 2018 growing to 298 MW of load in 2023 ([redacted])
- Revere/Chelsea Load Pocket (within Subarea F)

- Loss of [redacted] disconnects 349 MW of load in 2018 growing to 357 MW of load in 2023 (Loss [redacted])

Divergent Case Conditions

Divergent cases occurred for a number of contingencies associated with 115 kV line outages in [redacted]. The following table provides the contingency pairs that resulted in non-convergent cases and the associated counts for the number of cases where each contingency pair resulted in non-convergence. A contingency pair with a count of 37 indicated that the particular contingency pair did not converge in any of the dispatches for a given year.

Table 5-28
2018 and 2023 Divergent Contingency Cases

Element Out of Service	Contingency	2018	2023
[redacted]	[redacted]T	0	2
[redacted]	[redacted]B	23	23
[redacted]	[redacted]	36	37
	[redacted]	37	37
	[redacted]	37	37
	[redacted]	37	37
	[redacted]	36	37
	[redacted]	34	37
	[redacted]	37	37
[redacted]	[redacted]	33	31
	[redacted]	37	36
	[redacted]	36	35
	[redacted]	34	29
	[redacted]	36	34
	[redacted]	30	37
	[redacted]	23	22
	[redacted]	36	36
	[redacted]	37	37
	[redacted]	34	31
	[redacted]	30	36
[redacted]	[redacted]	14	0
	[redacted]B	7	1
	[redacted]	7	0
[redacted]	[redacted]SB	1	1
	[redacted]	23	1
	[redacted]	1	1

5.3 Stability Performance Criteria Compliance

Not applicable for this study.

5.3.1 Stability Test Results Summary

Not applicable for this study.

5.4 Short Circuit Performance Criteria Compliance

The short circuit breaker duty evaluation was performed for the 2018 model year. This assessment considers the short circuit fault duty seen by individual breakers for worst case faults under the modeled conditions. The modeled condition includes assumptions concerning breaker interrupting characteristics as well as assumptions concerning dispatch of generation is running. Breakers exceeding 100% fault duty are in violation of reliability standards.

5.4.1 Short Circuit Test Results Summary

Table 5-29 shown below is a summary of the results of a breaker evaluation study that considered the worst case breaker fault duty for each breaker in the study area as compared to the breaker's rated interrupting capability. The values shown in Appendix H are based on 2018 model conditions and show values in percent of breaker capability ratings.

Table 5-29 2018 Greater Boston Area Stations with Over Duty Breakers

Station	Breaker Duty
Mystic 115 kV	[redacted]
Kingston 115 kV	[redacted]
Brighton 115 kV	[redacted]
K Street 115 kV	[redacted]
West Medway 345 kV	[redacted]
Salem Harbor 115 kV	[redacted]
Wakefield Junction 115 kV	[redacted]

Section 6
Conclusions on Needs Analysis

The results of the assessment conducted of the Greater Boston area transmission performance against transmission reliability standards for the projected 2018 and 2023 system conditions in this study indicate that there are a significant number of thermal and voltage violations across a number of subareas within the Greater Boston system. The Greater Boston area transmission system fails to meet established reliability criteria standards, and measures should be developed to mitigate the problems identified. The study has determined the specific year in which violations first emerge and based on this information system upgrades necessary to mitigate these violations in criteria should be implemented as soon as practical.

The specific set of criteria and standards that the transmission system serving Greater Boston fails to meet includes the following:

- NERC Reliability Standards TPL-001-4 Category P1, P2, P3, P4, and P6 performance requirements.
- NPCC Regional Reliability Reference Directory # 1 Design and Operation of the Bulk Power System Section 5.4 Transmission Design Criteria requirements.
- ISO New England Planning Procedure No. 3 Reliability Standards For The New England Area Bulk Power Supply System Section 3.0 Area Transmission requirements.

6.1 Year of Need Assessment

An assessment of the initial year and load level that the system fails to meet the established criteria was performed based on evaluation of thermal overload conditions. This evaluation was performed for N-1 overloads and N-1-1 overloads under design case conditions. The process used was based on a linear projection of the load level at which overloaded elements first fail to meet criteria. The projection for each element with a thermal violation was derived by comparing the 2018 loading to the 2023 loading for specific contingency and dispatch conditions that resulted in the worst case thermal violation to establish a rate of change in loading. This rate of change was then used to calculate the load level at which an overload would first be seen. This process provides an approximation of when contingency based loading on specific elements will reach a threshold level and actual overloads may occur earlier or later than the results indicate. The results of this analysis are shown in Table 6-1 and Table 6-2 below. Please note that transmission cables that operate as a cable pair where both cables are overloaded only report loading data for the highest loaded element as these values were used in determining the year of need. The year of need is based on the loads for the Boston RSP subarea and the values shown in Tables 6-1 and 6-2 below represent the Boston RSP subarea loads.

Table 6-1 Greater Boston N-1 Year of Need Assessment

Greater Boston Area N-1 Testing Year of Need Calcuation Results								
					LTE Loading for Year		Year of Need	Critical Load Level
Sub-Area	Element ID	Monitored Element	LTE Rating	Contingency	2018	2023		
A-3	394	104127 SEABROOK 345 104128 NU_394_SBK 345 1	[redacted]	[redacted] 1	111	113	Pre-2013	4680
B-2	WOBURN 345A XFMR	110799 WOBURN 115 110756 WOBURN 345 1		[redacted]	105	109	2013	6463
B-3	533-508	110805 HARTWELL 115 110806 LEXINGTON 115 1		[redacted]	100	104	2018	6868
B-5	211-514	110799 WOBURN 115 110820 MYSTIC GIS 115 1		[redacted]	195	204	Pre-2013	2740
B-6	282-520 / 282-521	110811 WATERTWN 520 115 903019 282-520_BRTN 115 1A		[redacted]	128	131	Pre-2013	4075
C-1	329-510 / 329-511	110816 SOMERVIL 510 115 903025 329-510_MYST 115 1B		[redacted]	109	113	Pre-2013	5930
C-3	385-511	110832 KINGSTN ST A 115 903039 385-511_HIGH 115 1A		[redacted]	115	120	Pre-2013	5690
C-4	250-516 / 250-517	110818 MYSTIC MA 115 903013 250-516_HAWK 115 1B		[redacted]	141	141	Pre-2013	N/A
C-5	110-510 / 110-511	110854 WASH_TAP 510 115 903006 110-510_BAKR 115 1A		[redacted]	120	113	2032	7856
C-7	324 / 372	110766 KINGSTON ST 345 903005 372_MYST 345 2B		[redacted]	115	116	Pre-2013	N/A
D-1	W-23	113332 FITCH ROAD 69.0 114785 WOODSIDE 69.0 1		[redacted]	100	105	2018	6858
D-3	W-23W	114779 MWRA_W23W 69.0 114780 NBORO_W23W 69.0 1		[redacted]	113	119	Pre-2013	6003
E-1	447-508	110900 HOLBROOK 115 114765 5 RANDLPH508 115 1		[redacted]	108	111	Pre-2013	5776
H-2	M139	113969 BILERCA 39_T 115 113987 TEWKSBURY 115 1		[redacted]	99	101	2020	6986

Table 6-2 Greater Boston N-1-1 Year of Need Assessment

Greater Boston Area N-1-1 Testing Year of Need Calcuation Results										
							LTE Loading for Year		Year of Need	Critical Load Level (MW)
Sub-Area	Element ID	Monitored Element	LTE Rating	Units Out	Line Out	Contingency	2018	2023		
A-10	I135	104990 FITZWILLIAM 115 105001 NU_I135_NGR 115 1	[redacted]	1-2 Units	LN_394	[redacted]	101	107	2017	6789
A-13	N214	106013 N.LITCHFLD2 230 113955 TEWKSBURY 230 1	[redacted]	1-2 Units	LN_394	[redacted]	107	111	2021	7021
A-2	337	113950 SANDY POND 345 113951 TEWKSBURY 345 1	[redacted]	1-2 Units	GN_MYS9_CC_TIE_CLSD	[redacted]	103	109	2021	7082
A-3	394	104127 SEABROOK 345 104128 NU_394_SBK 345 1	[redacted]	1-2 Units	GN_MYS9_CC_TIE_CLSD	[redacted]	105	107	Pre-2013	5880
A-5	SANDY POND XFMR#1	113950 SANDY POND 345 114027 SANDY PD T1 99.0 1	[redacted]	1-2 Units	LN_394	[redacted]	133	136	Pre-2013	3347
A-8	A253	104111 MERRIMACK 230 104113 NU_A253_NGR 230 1	[redacted]	1-2 Units	LN_394	[redacted]	118	124	Pre-2013	5689
A-9	B202S	106011 DUNBARTAN TP 230 106013 N.LITCHFLD2 230 1	[redacted]	1-2 Units	LN_394	[redacted]	108	113	Pre-2013	6305
B-1	391-508	110804 BURLINGTN MA 115 110805 HARTWELL 115 1	[redacted]	1-2 Units	TF_WOBRN_345A	[redacted]	112	124	Pre-2013	6424
B-2	WOBURN 345A XFMR	110799 WOBURN 115 110756 WOBURN 345 1	[redacted]	1-2 Units	LN_533-508	[redacted]	150	158	Pre-2013	4462
B-3	533-508	110805 HARTWELL 115 110806 LEXINGTON 115 1	[redacted]	1-2 Units	TF_WOBRN_345A	[redacted]	152	167	Pre-2013	5563
B-5	211-514	110799 WOBURN 115 110820 MYSTIC GIS 115 1	[redacted]	1-2 Units	TF_KING_345B	[redacted]	266	277	Pre-2013	879
B-6	282-520 / 282-521	110811 WATERTWN 520 115 903019 282-520_BRTN 115 1B	[redacted]	1-2 Units	LN_282-521	[redacted]	204	216	Pre-2013	3586
B-7	351 / 358	110759 MYSTIC MA 345 903003 358_NCAMB 345 1B	[redacted]	1-2 Units	LN_338	[redacted]	141	146	Pre-2013	3500
B-8	346 / 365	110758 N. CAMBRIDGE 345 903000 346_WOBURN 345 1B	[redacted]	1-2 Units	LN_339	[redacted]	151	151	Pre-2013	N/A
C-1	329-510 / 329-511	110813 BRIGHTON A 115 903026 329-510_SOMR 115 1B	[redacted]	1-2 Units	LN_329-511	[redacted]	126	145	Pre-2013	6318
C-2	329-512 / 329-513	110830 KINGSTN ST W 115 903031 329-512_CARV 115 1B	[redacted]	1-2 Units	LN_385-512	[redacted]	121	126	Pre-2013	5212
C-3	385-510 / 385-511	110832 KINGSTN ST A 115 903039 385-511_HIGH 115 1A	[redacted]	1-2 Units	TF_MYST_345A	[redacted]	162	168	Pre-2013	2903
C-3	385-513	110830 KINGSTN ST W 115 903042 385-513_KST 115 2B	[redacted]	1-2 Units	LN_329-512	[redacted]	143	146	Pre-2013	1945
C-4	250-516 / 250-517	110842 CHATHAM 516 115 903015 250-516_KST 115 1B	[redacted]	1-2 Units	LN_250-517	[redacted]	135	141	Pre-2013	4181
C-5	110-510 / 110-511	110854 WASH_TAP 510 115 903006 110-510_BAKR 115 1A	[redacted]	1-2 Units	LN_3164	[redacted]	141	148	Pre-2013	4683
C-7	324 / 372	110766 KINGSTON ST 345 903004 324_MYST 345 1B	[redacted]	1-2 Units	LN_372	[redacted]	117	119	Pre-2013	3182
C-8	329-530 / 329-531	110815 N. CAMBRIDGE 115 903036 329-531_BRTN 115 1B	[redacted]	1-2 Units	TF_NCAM_345B	[redacted]	129	135	Pre-2013	4998
D-1	W-23	113332 FITCH ROAD 69.0 114785 WOODSIDE 69.0 1	[redacted]	1-2 Units	LN_455-507	[redacted]	213	213	Pre-2013	N/A
D-2	E157	113271 WYMNGRDN57_T 115 113275 E157_M165_J 115 1	[redacted]	1-2 Units	LN_455-507	[redacted]	131	136	Pre-2013	4227
D-3	W-23W	114779 MWRA_W23W 69.0 114780 NBORO_W23W 69.0 1	[redacted]	1-2 Units	LN_455-507	[redacted]	265	265	Pre-2013	N/A
D-4	X-24W	113339 N GRAFTON 69.0 114784 WESTBORO 69.0 1	[redacted]	1-2 Units	LN_E157W-W	[redacted]	184	185	Pre-2013	N/A
D-5	433-507	110870 FRAMINGHAM 115 110871 SPEEN STREET 115 1	[redacted]	1-2 Units	LN_394	[redacted]	136	137	Pre-2013	N/A
D-6	282-507	110810 WALTHAM PS 115 110872 SUDBURY 115 1	[redacted]	1-2 Units	TF_WMED_345B	[redacted]	105	110	Pre-2013	6429
D-7	240-508	110868 SHERBORN 115 110870 FRAMINGHAM 115 1	[redacted]	1-2 Units	LN_394	[redacted]	108	108	Pre-2013	2102
D-7	274-509	110866 MEDWAY 115 110868 SHERBORN 115 1	[redacted]	1-2 Units	LN_E157W-W	[redacted]	101	106	2017	6758
D-7	455-507	110868 SHERBORN 115 110869 W FRAMINGHAM 115 1	[redacted]	1-2 Units	LN_E157W-W	[redacted]	132	137	Pre-2013	4406
D-7	513-507	110869 W FRAMINGHAM 115 115027 NG513-507NST 115 1	[redacted]	1-2 Units	LN_E157W-W	[redacted]	106	111	Pre-2013	6348
D-9	N-40 A&B	113332 FITCH ROAD 69.0 113346 PRATTS JCT 69.0 1	[redacted]	1-2 Units	LN_455-507	[redacted]	126	127	Pre-2013	N/A
E-1	447-508 / 447-509	110895 WEST WALPOLE 115 110897 WALPOLE 509 115 1	[redacted]	1-2 Units	LN_451-536	[redacted]	118	125	Pre-2013	5885
E-4	3162	110862 K STREET 2 345 903062 3162_STGTN 345 1A	[redacted]	1-2 Units	LN_394	[redacted]	98	101	2021	7090
E-4	3163	110790 K STREET 1 345 903063 3163_STGTN 345 1A	[redacted]	1-2 Units	LN_394	[redacted]	99	102	2020	6946
E-5	HYDE PARK 345A XFMR	110791 HYDE PARK 115 110788 HYDE PARK 345 1	[redacted]	1-2 Units	LN_394	[redacted]	107	108	Pre-2013	5150
E-6	282-602	110789 WALTHAM 230 110794 W MEDWAY A 230 1	[redacted]	1-2 Units	LN_394	[redacted]	99	104	2019	6910
F-1	F158N	114410 GOLDNHL45-58 115 114412 MAPLEWOOD 115 1	[redacted]	1-2 Units	LN_349XY-1	[redacted]	150	154	Pre-2013	1895
F-2	F158S	114409 EVERETT 115 114412 MAPLEWOOD 115 1	[redacted]	1-2 Units	LN_349XY-1	[redacted]	132	135	Pre-2013	2736
F-4	349 XY	110759 MYSTIC MA 345 115017 NGR_349X_NST 345 1	[redacted]	1-2 Units	TF_WALTHM_PS	[redacted]	99	105	2019	6898
F-6	Q169	114430 GE RIVER69_T 115 114448 LYNN Q169 115 1	[redacted]	1-2 Units	LN_488-518	[redacted]	110	116	Pre-2013	6082
H-1	T146-1	113974 E TWKSBRY_46 115 113987 TEWKSBURY 115 1	[redacted]	1-2 Units	LN_349XY-1	[redacted]	104	110	2015	6577
H-1	S145E	114405 RAILYARD_45 115 114417 SALEM HARBOR 115 1	[redacted]	1-2 Units	LN_T146E	[redacted]	129	129	Pre-2013	N/A
H-1	T146W	113999 N READING 46 115 114485 WAKEFLD146 115 1	[redacted]	1-2 Units	LN_349XY-1	[redacted]	117	129	Pre-2013	6242
H-2	M139	113969 BILERCA 39_T 115 113987 TEWKSBURY 115 1	[redacted]	1-2 Units	LN_N140_504	[redacted]	121	127	Pre-2013	5405
H-3	N140	113962 PINEHURST 115 113987 TEWKSBURY 115 1	[redacted]	1-2 Units	LN_M139_503	[redacted]	110	114	Pre-2013	5991

Table 6-1 and Table 6-2 Notes:

1. Critical Load Level is a linear projection of the Boston RSP subarea load level for which the thermal violation first appears.

2. Year of Need was limited to 2013 to capture the fact that system changes such as generation retirements and transmission system adjustments make linear projects before 2013 meaningless.

3. N/A was used for critical load level when the 2013 and 2018 facility loadings were approximately the same. A linear projection between two approximately identical points renders the result meaningless.

THIS APPENDIX CONTAINS INFORMATION THAT HAS BEEN REDACTED FOR CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII).

Section 7
Appendix A: Load Forecast

THIS APPENDIX CONTAINS INFORMATION THAT HAS BEEN REDACTED FOR CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII).

Table 7-1 2013 CELT Load Forecast

1.6 - Seasonal Peak Load Forecast Distributions

		Peak Load Forecast at Milder Than Expected Weather				Reference Forecast at Expected Weather	Peak Load Forecast at More Extreme Than Expected Weather				
Summer (MW)	2013	26470	26715	27045	27420	27840	28285	28735	29385	30135	30790
	2014	26900	27150	27485	27865	28290	28740	29200	29860	30620	31280
	2015	27410	27665	28005	28390	28825	29285	29750	30425	31185	31860
	2016	27910	28165	28515	28910	29350	29815	30295	30980	31740	32420
	2017	28325	28590	28940	29340	29790	30265	30750	31445	32210	32900
	2018	28675	28940	29295	29700	30155	30635	31125	31830	32615	33315
	2019	29025	29295	29655	30065	30525	31010	31505	32220	33010	33720
	2020	29345	29615	29980	30395	30860	31350	31855	32575	33380	34095
	2021	29670	29950	30315	30735	31205	31700	32210	32935	33755	34480
	2022	29970	30250	30625	31045	31520	32020	32535	33270	34105	34840
WTHI (1)		**78.49**	**78.73**	**79.00**	**79.39**	**79.88**	**80.30**	**80.72**	**81.14**	**81.96**	**82.33**
Dry-Bulb Temperature (2)		**88.50**	**88.90**	**89.20**	**89.90**	**90.20**	**91.20**	**92.20**	**92.90**	**94.20**	**95.40**
Probability of Forecast Being Exceeded		**90%**	**80%**	**70%**	**60%**	**50%**	**40%**	**30%**	**20%**	**10%**	**5%**
Winter (MW)	2013/14	22025	22140	22235	22295	22445	22595	22765	22865	23080	23505
	2014/15	22205	22320	22420	22480	22630	22780	22955	23055	23255	23685
	2015/16	22385	22500	22595	22660	22810	22960	23135	23235	23440	23870
	2016/17	22540	22660	22755	22815	22970	23125	23295	23400	23620	24050
	2017/18	22680	22795	22895	22955	23110	23265	23440	23540	23780	24205
	2018/19	22800	22920	23020	23080	23235	23390	23565	23670	23920	24345
	2019/20	22915	23035	23130	23195	23350	23505	23685	23785	24045	24470
	2020/21	23030	23150	23250	23315	23470	23625	23805	23910	24160	24590
	2021/22	23145	23265	23365	23425	23585	23745	23920	24025	24280	24705
	2022/23	23255	23380	23480	23540	23700	23860	24040	24145	24395	24820
Dry-Bulb Temperature (3)		**10.72**	**9.66**	**8.84**	**8.30**	**7.03**	**5.77**	**4.40**	**3.58**	**1.61**	**(1.15)**

Section 8

Appendix B: Upgrades Included in Base Case and Short Circuit Model

Table 8-1
Upgrades Included in Base Case Models

Maine	
Maine Power Reliability Program	MPRP - RSP ID: 1401-1472
Down East Reliability Improvement	RSP ID: 14
New Hampshire	
Second Deerfield 345/115 kV autotransformer Project	RSP ID: 277, 1137-1141
Rebuild Bellows Falls substation	RSP ID: 680
Western New Hampshire Solution	RSP ID: 1269-1275, 1346
Northern New Hampshire Solution	RSP ID: 1263, 1276
Central New Hampshire Solution	RSP ID: 1277-1278, 1300
Southern New Hampshire Solution	RSP ID: 1301-1304, 1306-1314, 1376, 1379
Seacoast New Hampshire Solution	RSP ID: 1316-1325
Massachusetts	
Auburn Area Transmission System Upgrades	RSP ID: 59, 887, 921, 919
Merrimack Valley / North Shore Reliability Project	RSP ID: 775-776, 782-783, 840
Long Term Lower SEMA Upgrades	RSP ID: 592, 1068, 1118. 1349-1351
Central/Western Massachusetts Upgrades	RSP ID: 924- 929, 931-932, 934-935, 937-950, 952- 955
NEEWS – Greater Springfield Reliability Project	RSP ID: 196, 259, 687-688, 818-820, 823, 826, 828-829, 1010, 1070-1075, 1078-1080, 1100-1105
Advanced NEEWS Interstate Projects	RSP ID: 1202, 1342
NEEWS – Interstate Reliability Project	RSP ID: 190, 1094, 1293
Salem Harbor Retirement Upgrades	RSP ID: 1257-1259
Rhode Island	
Greater Rhode Island Transmission Reinforcements	RSP ID: 484, 786, 788, 790-793, 913-918, 1098
NEEWS – Rhode Island Reliability Project	RSP ID: 795, 798-800, 1096-1097, 1099, 1106, 1109, 1331
NEEWS – Interstate Reliability Project	RSP ID: 794, 1233-1234, 1252, 1294-1298
Chase Hill	Crandall Street Substation RSP ID: 1253

Connecticut	
NEEWS – Greater Springfield Reliability Project	RSP ID: 816, 1054, 1369-1371, 137
NEEWS – Interstate Reliability Project	RSP ID: 191, 802, 810, 1085, 1090-1091, 1235
Advanced NEEWS Interstate Projects	RSP ID: 1235, 1245
Northeast Simsbury Substation 115 kV Circuit Breaker Project	RSP ID: 1230
Millstone 345 kV Circuit Separation & SLOD SPS System Retirement	RSP ID: 1218
Line 1990 Asset Condition Replacement Project	RSP ID: 1229

Table 8-2 Model Changes Included in the 2017Short Circuit Base Case

File Name	Change
2017 MASTER CASE 20130624-Starting Case for Update(No Brkrs).OLR	Original 2013 base case sent out for review on 6/20/2013
2017 MASTER CASE 20130624-Add RIRP, CCRP, IRP&GSRP-01(No Brkrs).OLR	Added all NEEWS projects including: • IRP (Card-Lake Road 3271 line, Lake Road-West Farnum 341 line) • RIRP (West Farnum-Kent County 359 line, 3rd Kent County auto, reconductor G185, S171S, T172S) • CCRP (North Bloomfield-Frost Bridge 3208 line, 2nd Frost Bridge auto, reconductor 3533, add 2nd Beseck shunt reactor • GSRP (Ludlow-Agawam 3196 line, Agawam-North Bloomfield 3216 line, Manchester-North Bloomfield 3642 line, reconfigure 395 line, add 2 Agawam autos, 2nd North Bloomfield auto, build/reconductor 1230, 1314,1426, 1481, 1552, 1723, 1904, 1254, 1702, 1803, 1601, 1768/1821, 1781, 1782, 1845, 1556, 1645, 1784 lines). Note that these changes were already in the case, but were not in service. Added West Walpole-Carver line
2017 MASTER CASE 20130624-Add MPRP-02(Mystic, Kingston& WMedway Breakers).OLR	• Added entire MPRP project • Updated ANP Bellingham and Blackstone GSU impedances and 336/3361 line impedances
2017 MASTER CASE 20130624-ADD OTHER SEMA & RI UPDATES-03(Boston Area Breakers).OLR	• Added Medway peakers • Added Everett peakers • Added Plainfield CT gen • Placed Cape Wind in service with Kingston-Auburn and Kingston-Brook Street 115 kV line upgrades • Added replacement Holbrook auto
2017 MASTER CASE 20130630-Additional Gen Projects-04(BOSTON AREA BREAKERS).OLR	• Added Towantic QP384 • Added Brockton CC QP178 • Added Northfield uprates • Added Palmer Renewable QP273 • Added NH Laidlow Berlin Biomass QR251

2017 MASTER CASE 20130701-Additional Transmission Projects-05(BOSTON AREA BREAKERS).OLR	• Added Salem Harbor RSP projects • Added Pittsfield-Greenfield Solution projects • Added National Grid Central Western MA projects
2017 MASTER CASE 20130702-06(NATIONAL GRID & NSTAR BRKRS).OLR	Removed Peabody generator
2017 MASTER CASE 20130806-07(NATIONAL GRID & NSTAR BRKRS).OLR	Corrected all Mystic GSU transformer zero-sequence impedances
2017 MASTER CASE 20130829-08(NATIONAL GRID & NSTAR BRKRS).OLR	• Removed AES Thames generator and GSU • Updated New Brunswick Equivalent (Note: The two equivalent sources were inadvertently omitted from this equivalent.) • Updated New York Equivalent • Corrected the Torrington terminal 115/69-kV autotransformer impedance (replacement) • Reconnected the A. L. Pierce generator at Wallingford that was inadvertently disconnected • Revised the Devon-Trumbull 1730 line impedances to match NX-9 data.
2017 MASTER CASE 20131117-09(NATIONAL GRID & NSTAR BRKRS).OLR	Corrected New Brunswick equivalent to add the two equivalent sources that were inadvertently omitted from Rev-08.

Section 9

Appendix C: Case Summaries and Load Flow Plots

Select the following link to open the case summary file: [redacted]

Select the following link to open the case summary file: [redacted]

Section 10

Appendix D: Generation Dispatch and Reactive Resources

Table 10-1
2023 Greater Boston Area Generation Dispatch Summary

BusName	LFCaseName
BOOTT HYDRO	[redacted]
CANAL G1	[redacted]
CANAL G2	[redacted]
CPC LOWELL	[redacted]
EDGAR GT1	[redacted]
EDGAR GT2	[redacted]
EDGAR ST	[redacted]
FRAMINGHAM	[redacted]
GE RIVER R&T	[redacted]
GE RIVER S&U	[redacted]
IPSWICH DSL	[redacted]
KENDALL CT	[redacted]
KENDALL JET	[redacted]
L STREET JET	[redacted]
LAWRENCE HYD	[redacted]
LENERGIA CT	[redacted]
LENERGIA ST	[redacted]
MALDEN MLS_T	[redacted]
MARBLEHEAD A	[redacted]
MARBLEHEAD B	[redacted]
MATEP 3	[redacted]
MATEP_CC	[redacted]
MATEP_DIESEL	[redacted]
MBTA	[redacted]
MYSTIC 7GT	[redacted]

BusName	[redacted]
MYSTIC 8ST	[redacted]
MYSTIC 9ST	[redacted]
MYSTIC GT 8A	[redacted]
MYSTIC GT 8B	[redacted]
MYSTIC GT 9A	[redacted]
MYSTIC GT 9B	[redacted]
MYSTIC JET	[redacted]
NEWINGTON_G1	[redacted]
NEWINGTON_S1	[redacted]
OGDEN MARTIN	[redacted]
PERRY ST 3	[redacted]
PILGRIM	[redacted]
PUTNAM 2	[redacted]
QP 387-2 5CT	[redacted]
QP 387-2 5ST	[redacted]
QP 387-2 6CT	[redacted]
QP 387-2 6ST	[redacted]
RESCO-SAUGUS	[redacted]
SEABROOK_G1	[redacted]
W MEDWAY J3	[redacted]
W MEDWAY JET	[redacted]
WATERS RVRJ1	[redacted]
WATERS RVRJ2	[redacted]
YARMOUTH #4	[redacted]

	LFCaseName
BusName	[redacted]
BOOTT HYDRO	[redacted]
CANAL G1	[redacted]
CANAL G2	[redacted]
CPC LOWELL	[redacted]
EDGAR GT1	[redacted]
EDGAR GT2	[redacted]
EDGAR ST	[redacted]
FRAMINGHAM	[redacted]
GE RIVER R&T	[redacted]
GE RIVER S&U	[redacted]
IPSWICH DSL	[redacted]
KENDALL CT	[redacted]
KENDALL JET	[redacted]
L STREET JET	[redacted]
LAWRENCE HYD	[redacted]
LENERGIA CT	[redacted]
LENERGIA ST	[redacted]
MALDEN MLS_T	[redacted]
MARBLEHEAD A	[redacted]
MARBLEHEAD B	[redacted]
MATEP 3	[redacted]
MATEP_CC	[redacted]
MATEP_DIESEL	[redacted]
MBTA	[redacted]
MYSTIC 7GT	[redacted]

BusName	[redacted]
MYSTIC 8ST	[redacted]
MYSTIC 9ST	[redacted]
MYSTIC GT 8A	[redacted]
MYSTIC GT 8B	[redacted]
MYSTIC GT 9A	[redacted]
MYSTIC GT 9B	[redacted]
MYSTIC JET	[redacted]
NEWINGTON_G1	[redacted]
NEWINGTON_S1	[redacted]
OGDEN-MARTIN	[redacted]
PERRY ST 3	[redacted]
PILGRIM	[redacted]
PUTNAM 2	[redacted]
QP 387-2 5CT	[redacted]
QP 387-2 5ST	[redacted]
QP 387-2 6CT	[redacted]
QP 387-2 6ST	[redacted]
RESCO-SAUGUS	[redacted]
SEABROOK_G1	[redacted]
W MEDWAY J3	[redacted]
W MEDWAY JET	[redacted]
WATERS RVRJ1	[redacted]
WATERS RVRJ2	[redacted]
YARMOUTH #4	[redacted]

	LFCaseName
BusName	[redacted]
BOOTT HYDRO	[redacted]
CANAL G1	[redacted]
CANAL G2	[redacted]
CPC LOWELL	[redacted]
EDGAR GT1	[redacted]
EDGAR GT2	[redacted]
EDGAR ST	[redacted]
FRAMINGHAM	[redacted]
GE RIVER R&T	[redacted]
GE RIVER S&U	[redacted]
IPSWICH DSL	[redacted]
KENDALL CT	[redacted]
KENDALL JET	[redacted]
L STREET JET	[redacted]
LAWRENCE HYD	[redacted]
LENERGIA CT	[redacted]
LENERGIA ST	[redacted]
MALDEN MLS_T	[redacted]
MARBLEHEAD A	[redacted]
MARBLEHEAD B	[redacted]
MATEP 3	[redacted]
MATEP_CC	[redacted]
MATEP_DIESEL	[redacted]
MBTA	[redacted]
MYSTIC 7GT	[redacted]

BusName	[redacted]
MYSTIC 8ST	[redacted]
MYSTIC 9ST	[redacted]
MYSTIC GT 8A	[redacted]
MYSTIC GT 8B	[redacted]
MYSTIC GT 9A	[redacted]
MYSTIC GT 9B	[redacted]
MYSTIC JET	[redacted]
NEWINGTON_G1	[redacted]
NEWINGTON_S1	[redacted]
OGDEN-MARTIN	[redacted]
PERRY ST 3	[redacted]
PILGRIM	[redacted]
PUTNAM 2	[redacted]
QP 387-2 5CT	[redacted]
QP 387-2 5ST	[redacted]
QP 387-2 6CT	[redacted]
QP 387-2 6ST	[redacted]
RESCO-SAUGUS	[redacted]
SEABROOK_G1	[redacted]
W MEDWAY J3	[redacted]
W MEDWAY JET	[redacted]
WATERS RVRJ1	[redacted]
WATERS RVRJ2	[redacted]
YARMOUTH #4	[redacted]

Table 10-2
Shunt Reactive Resources at 69 kV and Above for the Greater Boston Area

Greater Boston Needs Assessment Shunt Compensation Table											
Bus Name	**Voltage (kV)**	**Min Reactive**	**Max Reactive**	**Bus Name**	**Voltage (kV)**	**Min Reactive**	**Max Reactive**	**Bus Name**	**Voltage (kV)**	**Min Reactive**	**Max Reactive**
3RIVERSN13_C	11S	0	61.1	HEYWOOD RD_C	11S	0	20	QUAKER HILL	115	0	S.4
AGAWAM_C	115	0	100.8	HG_CONVRTR_N	120	0	1S4	RAYMOND	11S	0	5.4
AMHERST_C	34S	0	S0	HG_CONVRTR_S	11S	0	140	REVERE_C	115	0	30
AMHERST_C	11S	0	14.4	HYANNIS J_C	11S	0	39	RILEY_C	11S	0	30
AUGUSTA EAST	11S	0	S.4	JACKMAN_C	11S	0	26.68	ROCKY RIVR_C	11S	0	25.2
BAKER ST_C1	11S	0	S3.6	K STREET 1_C	11S	0	S3.6	RUMFORD IP_C	11S	0	2S
BAKER ST_C2	11S	0	S3.6	K STREET 1_R	345	-89.42	0	S.GORHAM_C1	11S	0	50
BARNSTABLE_C	11S	0	3S.3	K STREET 2_C	11S	0	S3.6	S.GORHAM_C2	11S	0	S0
EAR SWP CAP	11S	0	S0	K STREET 2_R	11S	-76	0	SACKETT_C	11S	0	42
EEBERIVER_C	11S	0	39.9	K STREET 2_R	345	-89.42	0	SALEM HBR_C1	115	0	63
BELFAST	11S	0	10.8	KEENE ROAD_C	11S	0	1S	SALEM HBR_C2	11S	0	63
BELLOWSFLS_C	11S	0	30	KENT CO._C2	11S	0	63	SANDBAR_C	11S	0	24.7S
BERLIN CT_C	11S	0	126	KENT CO._CS6	11S	0	144	SANFORD_C	11S	0	30.6
BERLIN VT_C	11S	0	24.7S	KIMBALL RD_C	11S	0	60	SCHILLER_C1	115	0	S3.2
BRANDFORD_C	11S	0	37.8	LARRABEE_C	11S	0	30	SCHILLER_C2	11S	0	S3.2
BRUDIES ROAD	69	0	S.4	LEXINGTON_C	11S	0	S3.6	SEWALL ST	11S	0	10.8
CANTON_C	11S	0	50.4	LEXINGTON_R	34S	-159.42	0	SINGER316S_R	34S	-S0	0
CAPE	11S	0	10.8	LUDLOW_C	345	0	240	SINGER3280_R	34S	-S0	0
CAPE WIND_R1	11S	-3S	0	LYNDONVIL_C1	11S	0	12.S	SINGER3619_R	34S	-S0	0

Greater Boston Needs Assessment Shunt Compensation Table

Bus Name	Voltage (kV)	Min Reactive	Max Reactive	Bus Name	Voltage (kV)	Min Reactive	Max Reactive	Bus Name	Voltage (kV)	Min Reactive	Max Reactive
CAPE WIND_R2	115	-35	0	LYNDONVIL_C2	115	0	12.5	5INGER3921_R	345	-50	0
CAPE WIND_R3	115	-35	0	MADBURY_C	115	0	53.34	5NDYPD HVDC1	345	-160	279
CAPE WIND_R4	115	-35	0	MAGUIRE RD_C	115	0	50.86	5NDYPD HVDC2	345	-320	279
CHELSEA_C	115	0	36.7	MANCHE5TR_C1	115	0	151.2	5OUTHNGTN1_C	115	0	151.2
CHESTNUTHI_C	115	0	48.88	MANCHESTR_C2	115	0	151.2	SOUTHNGTN2_C	115	0	151.2
COOLIDGE_C1	115	0	25	MA5HPEE_C	115	0	35.3	STARK5_C	115	0	36
COOLIDGE_C2	115	0	25	MA5ON_C1	115	0	50	5TONY HIL_C1	115	0	25.2
COOLIDGE_R1	345	-59.92	0	MA5ON_C2	115	0	50	STONY HIL_C2	115	0	75.6
COOLIDGE_R2	345	-59.92	0	MERRIMACK_C	115	0	73.34	5TOUGHTON_R1	345	-89.42	0
COOPER ML_C1	115	0	50	MERRIMACK_C2	115	0	36.67	STOUGHTON_R2	345	-89.42	0
COOPER ML_C2	115	0	50	MIDDLEBURY_C	115	0	22.9	5TOUGHTON_R3	345	-89.42	0
CROWLEY5_C	115	0	50	MILLBURY_C1	115	0	63	5TOUGHTON_R4	345	-159.42	0
CUMBERLAND_C	115	0	14.4	MILLBURY_C3	115	0	63	SUDBURY_C	115	0	49.47
DARIEN_C	115	0	37.8	MONROE_C1	230	0	63	5UROWIEC_C1	115	0	50
DETROIT	115	0	4.5	MONROE_C2	230	0	63	SUROWIEC_C2	115	0	50
DEVENS 1	69	0	3.6	MONTVILLE_C	115	0	100.8	SUROWIEC_C3	115	0	50
DEVEN5 2	69	0	3.6	MO5HER5	115	0	10.8	TEWK5BURY_C1	115	0	63
DOVER MA_C	115	0	53.6	MY5TIC CT_C	115	0	50.4	TEWK5BURY_C2	115	0	63
E SHORE_C1	115	0	42	MY5TIC_C	115	0	53.6	TRENTON_C	115	0	10
E 5HORE_C2	115	0	42	MY5TIC_R	115	-76	0	VERNON VT_R	345	-60	0
EAGLE_C1	115	0	50	MY5TIC_R	345	-159.42	0	VT YANKEE_C	115	0	60
EAGLE_C2	115	0	50	N CAMBRDG_R1	115	-76	0	W FRMNGHAM_C	115	0	54.4

THIS APPENDIX CONTAINS INFORMATION THAT HAS BEEN REDACTED FOR CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII).

Greater Boston Needs Assessment Shunt Compensation Table

Bus Name	Voltage (kV)	Min Reactive	Max Reactive	Bus Name	Voltage (kV)	Min Reactive	Max Reactive	Bus Name	Voltage (kV)	Min Reactive	Max Reactive
EDGAR_R1	115	-40	0	N CAMBRDG_R2	115	-76	0	W RUTLAND_C1	115	0	25
EDGAR_R2	115	-40	0	N RUTLAND_C	115	0	24.75	W RUTLAND_C2	115	0	25
ELM STREET	115	0	6	N.CAMBRIDG_R	345	-159.42	0	W RUTLAND_X	345	-60	0
EPPING TAP_C	115	0	10	N-BLOOMFLD_C	115	0	151.2	W.WALPOLE_R	345	-159.42	0
ESSEX_C34	115	0	24.3	NEW HAVEN_R	345	-59.92	0	WATERSIDE_C	115	0	37.8
ESSEX_C35_36	115	0	48.6	NORWALK-JC_R	345	-75.02	0	WEARE_C	115	0	26.6
ESSEX_C37	115	0	24.3	NORWALK-JD_R	345	-75.02	0	WEBSTER_C1	115	0	53.34
ESSEX_C38	115	0	24.3	NORWAY	115	0	7.2	WEBSTER_C2	115	0	53.34
ESSEX_C39	115	0	24.3	NORWLK3280_R	345	-50	0	WHITE LAKE_C	115	0	20
FALMOUTH T_C	115	0	35.3	NORWLK3921_R	345	-50	0	WILLISTON_C	115	0	25.2
FRAMINGHAM_C	115	0	53.6	NRTH HAVEN_C	115	0	42	WINGLANE_C	115	0	35.3
FRANKLIN-D_C	115	0	37.8	NTHBORO RD_C	115	0	54	WOBURN_R1	115	-76	0
FRANKLN SQ_C	115	0	63	NTHBORO RD_C	69	0	72	WOBURN_R2	115	-76	0
FROST BRG_C1	115	0	151.2	OAK HILL_C	115	0	26.66	WOBURN_R3	115	-76	0
FROST BRG_C2	115	0	100.8	OCEANRDE19_C	115	0	24.44	WOODLAND_C	115	0	28.8
GEORGIA_TP_C	115	0	24.75	OCEANRDU18_C	115	0	24.44	WYMAN HYD_C	115	0	36
GLENBROOK_C1	115	0	172.8	ORLEANS_C	115	0	13.57				
GLENBROOK_C2	115	0	158.4	ORRINGTON_C1	115	0	67				
GRANITE_C61	115	0	25	ORRINGTON_C2	115	0	67				
GRANITE_C62	115	0	25	ORRINGTON_C3	115	0	67				
GRANITE_C64	115	0	25	PLEASANT_C	115	0	28.8				
GRANITE_C66	115	0	25	PLUMTREE_C	115	0	88.2				
HADDAM_C	115	0	37.8	PLUMTREE_R	345	-75.02	0				

THIS APPENDIX CONTAINS INFORMATION THAT HAS BEEN REDACTED FOR CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII).

Greater Boston Needs Assessment Shunt Compensation Table											
Bus Name	**Voltage (kV)**	**Min Reactive**	**Max Reactive**	**Bus Name**	**Voltage (kV)**	**Min Reactive**	**Max Reactive**	**Bus Name**	**Voltage (kV)**	**Min Reactive**	**Max Reactive**
HARTFRD VT_C	115	0	25	PODICK_C	115	0	14.4				
HARTWELL_CAP	115	0	36.7	PRATTS JCT_C	115	0	63				
HARWICH_C	115	0	21.2	PRIDESCORNER	115	0	10.8				

Section 11

Appendix E: Assessment Criteria – Steady State Thermal and Voltage Criteria

Table 11-1
Steady State Thermal Criteria

SYSTEM CONDITION	TIME INTERVAL	MAXIMUM ALLOWABLE FACILITY LOADING
Pre-contingency (all lines in)	Continuous	Normal rating
Post-contingency	Less than 15 minutes after contingency occurs	Short Time Emergency (STE) Rating[1]
	More than 15 minutes after contingency occurs	Long Time Emergency (LTE) Rating

[1] Post-contingency loading above LTE but below STE is considered acceptable as long as prompt system action (local phase shifter adjustment, generation runback, or special protection system-SPS operation) could reduce loading below LTE within 15 minutes.

Table 11-2
Steady State Voltage Criteria

Transmission Owner	**Voltage Level**	**Bus Voltage Limits (Per-Unit)**	
		Normal Conditions	**Emergency (Contingency) Conditions**
Northeast Utilities	230 kV and above	0.98 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.95 to 1.05
National Grid	230 kV and above	0.98 to 1.05	0.95 to 1.05
	115 kV and below[1]	0.95 to 1.05	0.90 to 1.05
Millstone/Seabrook	345 kV	1.00 to 1.05	1.00 to 1.05
VT Yankee/Pilgrim	345 kV	0.99 to 1.05	0.99 to 1.05
Sandy Pond	345 kV	1.00 to 1.05	1.00 to 1.05
Other Transmission Owners	230 kV and above	0.95 to 1.05	0.95 to 1.05

[1] Buses that are part of the Bulk Power System, and other buses deemed critical by National Grid Network Operations shall meet requirements for buses that are 230 kV and above.

Section 12
Appendix F: Contingency List

12.1 Peak Load N-1 Contingency and Initial N-1-1 Contingency List

Table 12-1
Peak Load Contingencies Tested for All Cases and Sensitivities

BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
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Table 12-2 Initial Contingencies Applied for N-1-1 Peak Load Testing in All Cases and Sensitivities

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12.2 Light and Minimum Load N-1 Contingency and Initial N-1-1 Contingency List

Table 12-3 Light and Minimum Load Contingencies Tested for All Cases and Sensitivities

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Table 12-4 Initial Contingencies Applied for N-1-1 Minimal and Light Load Testing in All Cases and Sensitivities

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
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[redacted]	[redacted]
[redacted]	[redacted]
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[redacted]	[redacted]

12.3 Incorporating Dual Line Ratings for Cables with Common Circulation / Proximity

As a part of the post FCA 7 Greater Boston study changes to the ratings of underground cable facilities on the NSTAR transmission system have been included. An impact on the cable ratings that was previously not captured in the basecase models was the effect of the loss of a companion circuit on the rating of a cable. A companion underground circuit of circuit A is defined as a circuit B that shares the same duct bank with A, and may possibly have a common oil circulation. The common oil circulation would be such that oil flows from Station 1 to 2, through circuit A and returns back from station 2 to 1 via circuit B.

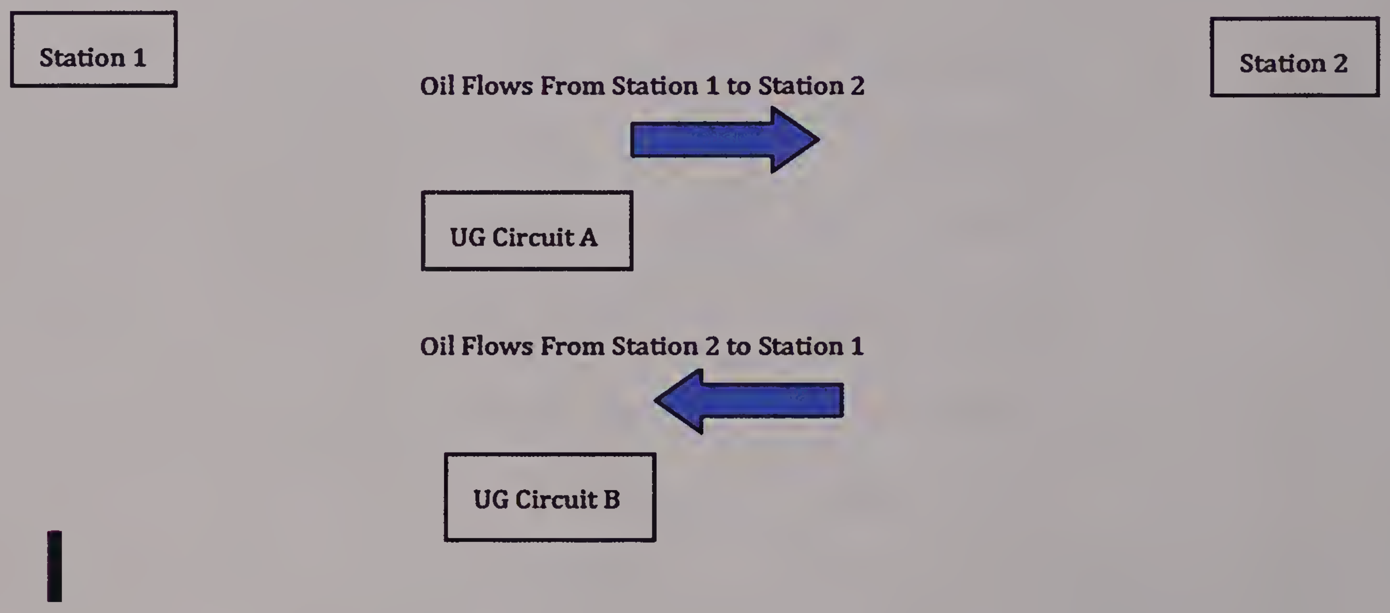
Station 1
Station 2
Oil Flows From Station 1 to Station 2
UG Circuit A
Oil Flows From Station 2 to Station 1
UG Circuit B

Figure 12-1 Illustration of Cables with Common Circulation

With a fault on one of the cables, for example Circuit B, the circulation will need to be interrupted to prevent the contamination of the circulation oil. The resultant loss of circulation for circuit A would tend to reduce the rating of the circuit. However, the fact that circuit B will be out of service, reduces the heat from an adjacent source that would tend to increase the ratings on circuit A. In calculating the line ratings post loss of the companion line both these factors will need to be accounted for.

For companion lines without a common circulation, the loss of the companion circuit, would only take out the adjacent heat source, and in general would increase the ratings on the line.

For each instance of such cables, ratings were calculated for both "Companion line in-service" and "Companion line Out-of-service". However, the power flow analysis software being employed by the study, does not account for conditional line ratings. Hence, a work around had to be developed to model the line ratings. The following example of the two 345 kV underground cables between

Mystic and North Cambridge will serve as a demonstration of the methodology employed for this purpose.

The following Figure 2 demonstrates the existing model for 351 and 358. Each line has a set of ratings and impedances that matches the field data.

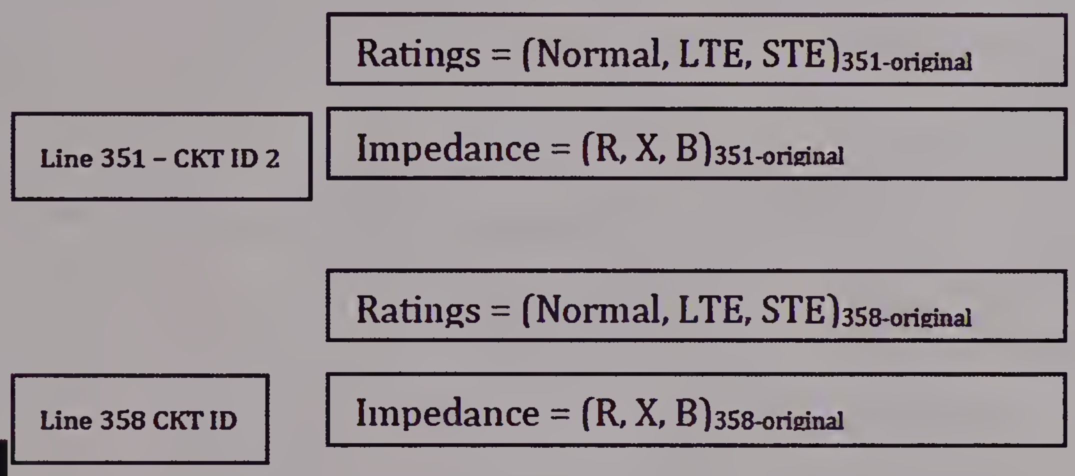
Ratings = (Normal, LTE, STE)$_{351\text{-original}}$
Line 351 – CKT ID 2
Impedance = (R, X, B)$_{351\text{-original}}$
Ratings = (Normal, LTE, STE)$_{358\text{-original}}$
Line 358 CKT ID
Impedance = (R, X, B)$_{358\text{-original}}$

Figure 12-2 351 and 358 Existing Model

The following figure demonstrates the modifications made to the model to account for the two ratings. We call the ratings of 351 as: 351- with 358 In-service and 351-with 358 Out-of-service. Each line is divided into three segments with the circuit IDs ending with A, B and C. For line 351 which has an original circuit ID of 2, the ratings would be 2A, 2B and 2C. The 2C circuit has no ratings data but has the impedance data for the line. The segments 2A and 2B have two sets of ratings. The circuit 2A is normally closed and has the ratings assuming the companion line 358 is in-service. The circuit 2C is normally open and has the ratings assuming the companion line 358 is out-of-service.

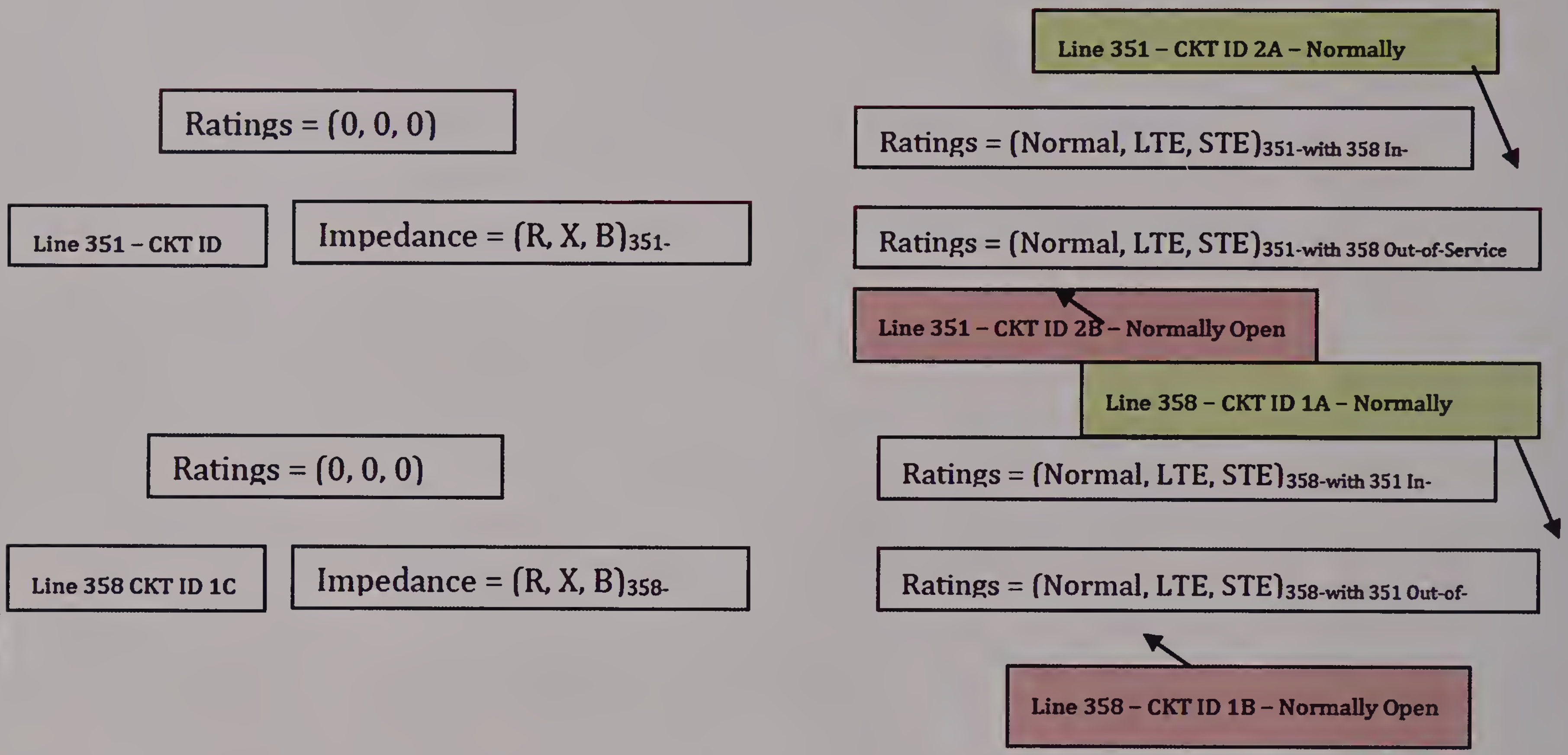
Line 351 – CKT ID 2A – Normally
Ratings = (0, 0, 0)
Ratings = (Normal, LTE, STE)$_{351\text{-with 358 In-}}$
Line 351 – CKT ID
Impedance = (R, X, B)$_{351-}$
Ratings = (Normal, LTE, STE)$_{351\text{-with 358 Out-of-Service}}$
Line 351 – CKT ID 2B – Normally Open
Line 358 – CKT ID 1A – Normally
Ratings = (0, 0, 0)
Ratings = (Normal, LTE, STE)$_{358\text{-with 351 In-}}$
Line 358 CKT ID 1C
Impedance = (R, X, B)$_{358-}$
Ratings = (Normal, LTE, STE)$_{358\text{-with 351 Out-of-}}$
Line 358 – CKT ID 1B – Normally Open

Figure 12-3 Illustration of modeling for 351 and 358

To see how the modeling works, it is best to observe the different scenarios that line 351 will be under.

1. 351 and 358 in-service
2. 358 out-of-service
3. 358 out-of-service + 351 out-of-service as the second contingency

351 and 358 in-service

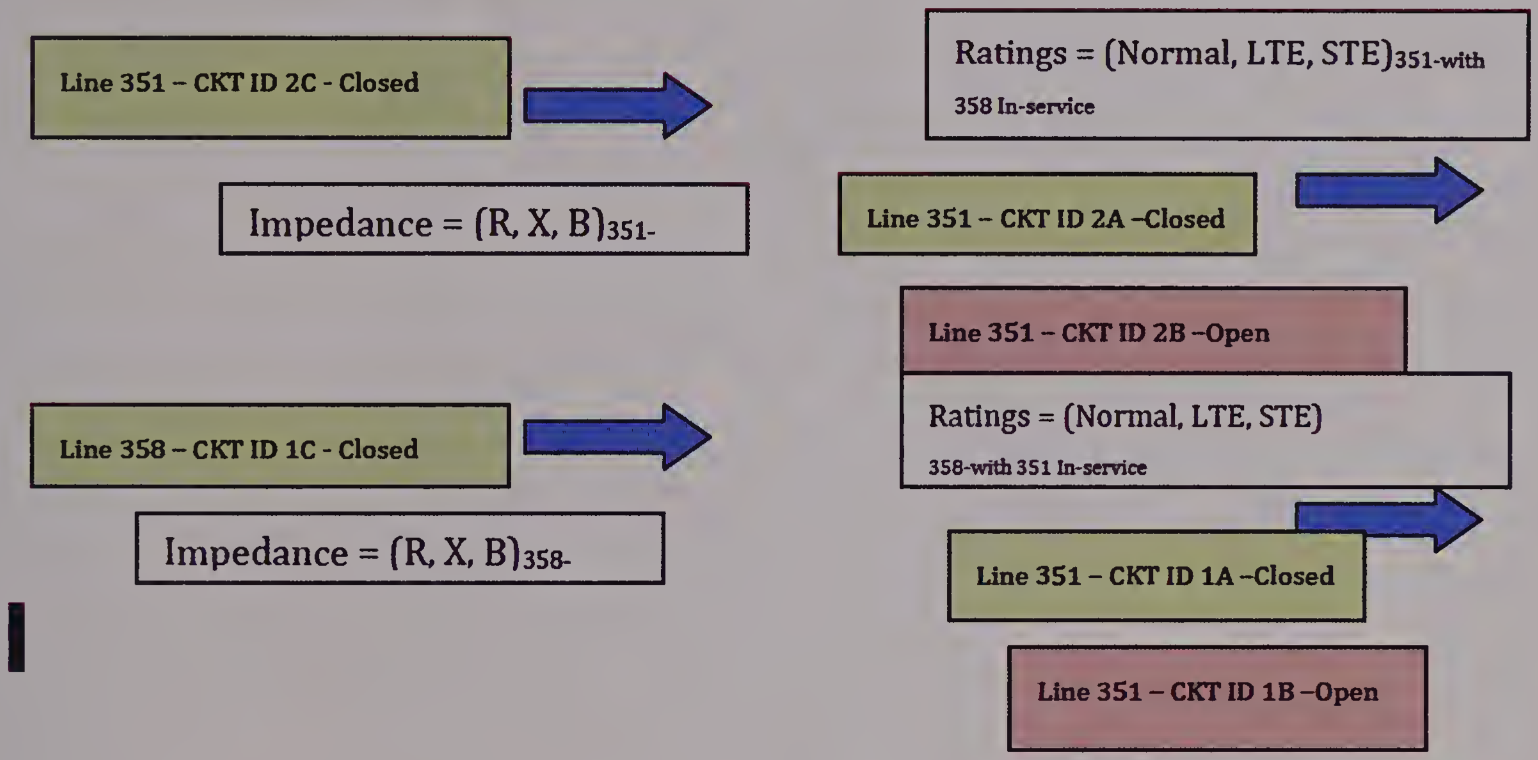
Line 351 – CKT ID 2C - Closed
Ratings = (Normal, LTE, STE)351-with 358 In-service
Impedance = (R, X, B)351-
Line 351 – CKT ID 2A –Closed
Line 351 – CKT ID 2B –Open
Line 358 – CKT ID 1C - Closed
Ratings = (Normal, LTE, STE) 358-with 351 In-service
Impedance = (R, X, B)358-
Line 351 – CKT ID 1A –Closed
Line 351 – CKT ID 1B –Open

Figure 12-4 351 and 358 In-service

With 351 and 358 in-service, the circuit "C" stays in-service for both lines, and the circuits "A" stay in-service for both lines. As a result power flows on both lines and the ratings assume the companion line is in-service.

358 out-of-service

With 358 OOS, the circuits "C" and "A" of 358 are taken out of service. Additionally, the circuit "A" of 351 is taken out of service, and the circuit "B" of 351 is put into service. This results in the rating of line 351 to change to reflect the 358 out of service rating.

A similar change is done when 351 is taken out of service, to reflect the changed rating on 358.

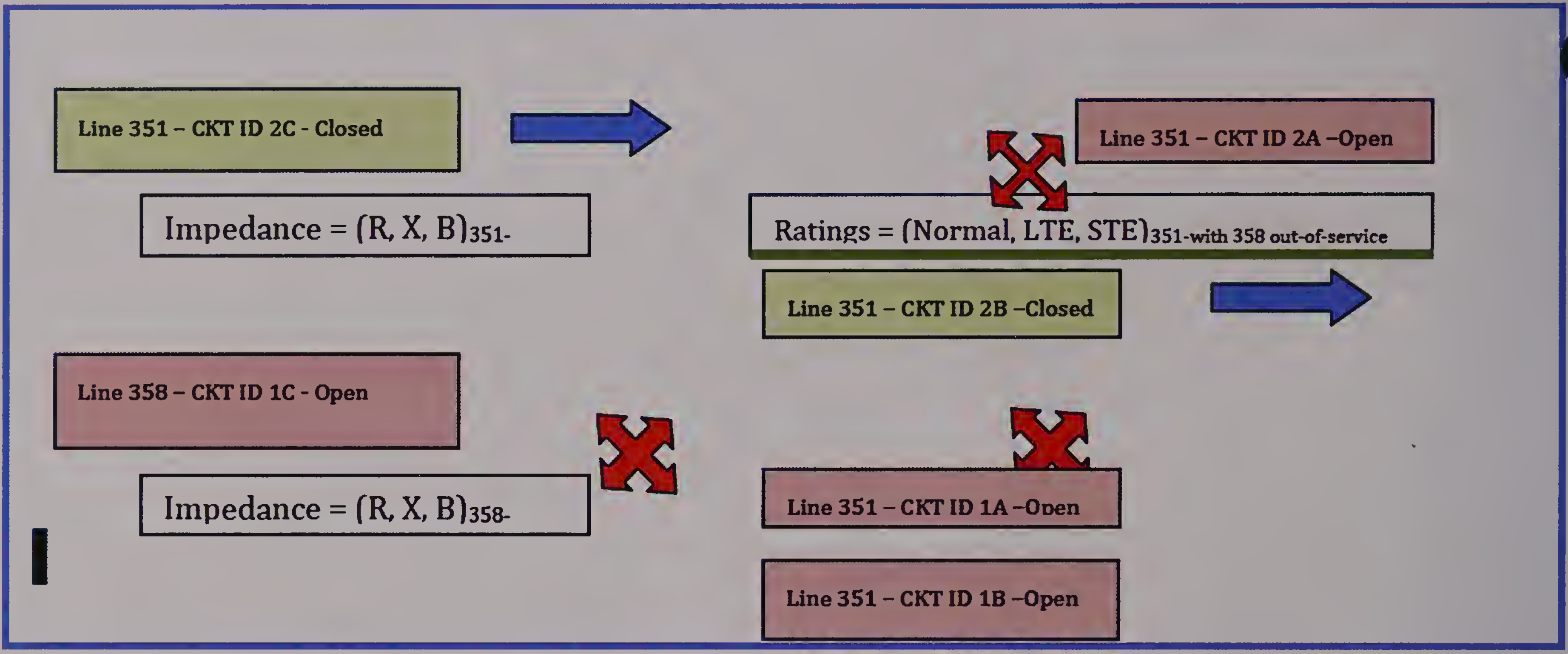
Line 351 – CKT ID 2C - Closed
Impedance = (R, X, B)351-
Line 351 – CKT ID 2A –Open
Ratings = (Normal, LTE, STE)351-with 358 out-of-service
Line 351 – CKT ID 2B –Closed
Line 358 – CKT ID 1C - Open
Impedance = (R, X, B)358-
Line 351 – CKT ID 1A –Open
Line 351 – CKT ID 1B –Open

Figure 12-5 351 and 358 In-service

358 out-of-service followed by loss of 351

With 358 out of service, if 351 is lost as a contingency, then a similar action will be performed where the "A" and "C" circuits of 351 will be taken out of service, and the "A" circuit of 358 will be taken out of service and the "B" circuit will be put into service. Since this change will be incremental to the change in Figure 4 above, the net impact is demonstrated in Figure 5. The net result would be no flow on either 351 or 358 since the "C" circuits are out of service. The "B" circuits being in-service have no impact on the flows on the line.

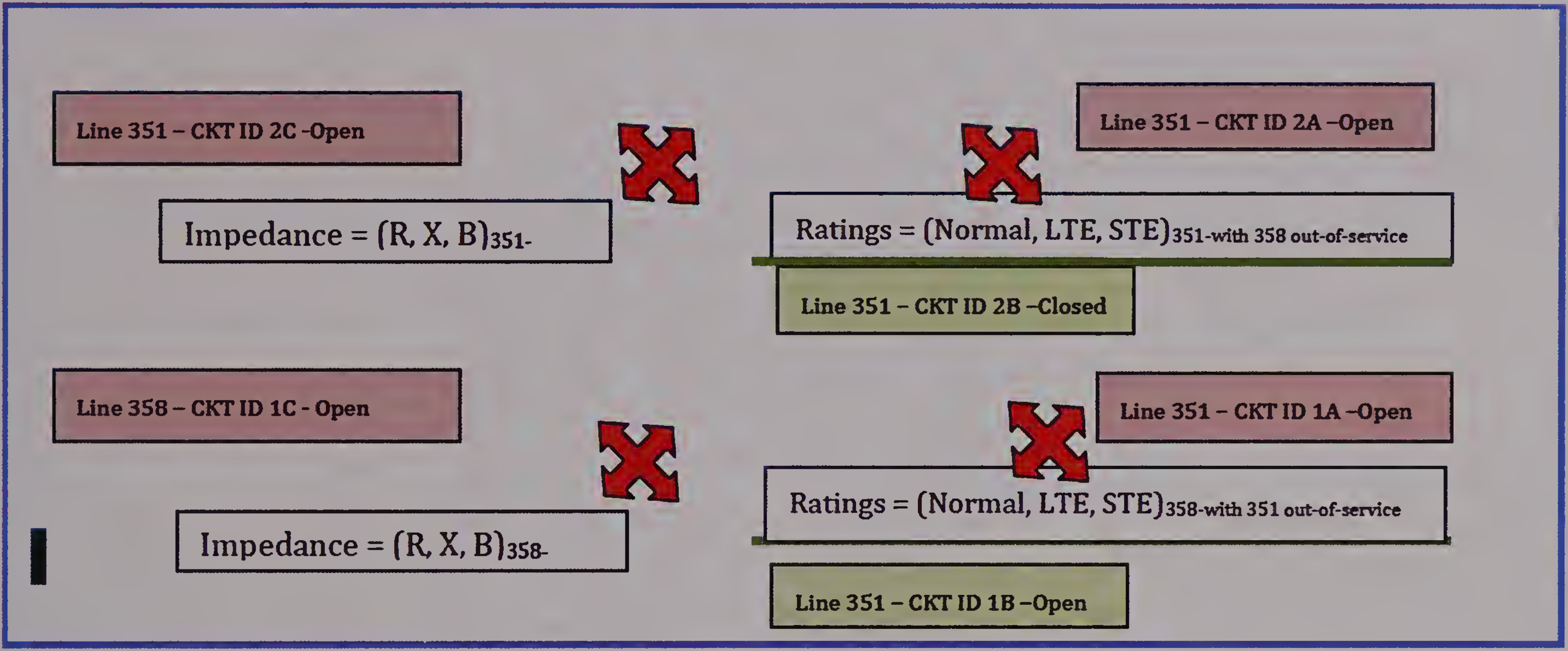
Line 351 – CKT ID 2C -Open
Impedance = (R, X, B)351-
Line 351 – CKT ID 2A –Open
Ratings = (Normal, LTE, STE)351-with 358 out-of-service
Line 351 – CKT ID 2B –Closed
Line 358 – CKT ID 1C - Open
Impedance = (R, X, B)358-
Line 351 – CKT ID 1A –Open
Ratings = (Normal, LTE, STE)358-with 351 out-of-service
Line 351 – CKT ID 1B –Open

Figure 12-6 351 and 358 In-service

Hence based on the above 3 scenarios it has been demonstrated that the modified model would produce the system conditions required to be modeled under the different conditions. Changes will need to made to the contingency file to model the contingency as following

Loss of 351:

1. Take out 351 – Circuit 2C
2. Take out 351 – Circuit 2A
3. Take out 358 – Circuit 1A
4. Put in-service 358 – Circuit 1B

Thus, the previous definition of 351, "Take out 351 – Circuit 2", will be replaced by the four elements above in the contingency file to match the modified case.

Additional Buses Created:

In order to model the above line, for each line, a new bus needs to be added to model the "A", "B" and "C" circuits. These new buses need to be excluded from the monitor file since they are just dummy buses to model different line ratings and not actual points where physical equipment exists.

Table 12-5 Greater Boston Area Updated Cable Pair Ratings

Line number	Terminal 1	Terminal 2	Proposed Ratings (Companion Cable in-service if applicable)			Proposed Ratings (Companion Cable out-of-service if applicable)		
			Normal	LTE	STE	Normal	LTE	STE
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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THIS APPENDIX CONTAINS INFORMATION THAT HAS BEEN REDACTED FOR CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII).

Line number	Terminal 1	Terminal 2	Proposed Ratings (Companion Cable in-service if applicable)			Proposed Ratings (Companion Cable out-of-service if applicable)		
			Normal	LTE	STE	Normal	LTE	STE
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Line number	Terminal 1	Terminal 2	Proposed Ratings (Companion Cable in-service if applicable)			Proposed Ratings (Companion Cable out-of-service if applicable)		
			Normal	LTE	STE	Normal	LTE	STE
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Section 13
Appendix G: Contingency Results

2018 N-1 and N-1-1 Thermal Results

[redacted]

2023 N-1 and N-1-1 Thermal Results

[redacted]

[redacted]

N-1 and N-1-1 Voltage Results

[redacted]

THIS APPENDIX CONTAINS INFORMATION THAT HAS BEEN REDACTED FOR CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII).

Section 14 Appendix H: Short-Circuit Results

Station	BREAKER	BKR Capability	Max DUTY in Percent	Station	BREAKER	BKR Capability	Max DUTY in Percent	Station	BREAKER	BKR Capability	Max DUTY in Percent
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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THIS APPENDIX CONTAINS INFORMATION THAT HAS BEEN REDACTED FOR CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII).

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Section 15

Appendix I: NERC Compliance Statement

This report is the first part of a two part process used by ISO-NE to assess and address compliance with NERC TPL standards. This Needs Assessment report provides documentation of an evaluation of the performance of the system as contemplated under the TPL standards to determine if the system meets compliance requirements. The Solution Study report is a complementary report that documents the study to determine which, if any, upgrades should be implemented along with the in-service dates of proposed upgrades that are needed to address the needs documented in the Needs Assessment report. The Needs Assessment Study and the Solution Study reports taken together provide the necessary evaluations and determinations required under the NERC TPL standards.

This study provides a detailed assessment of Greater Boston area of New England's electric system performance for review of the system performance expected for years 2018 and 2023. This study shows performance for NERC Categories P1 through P7 as defined in the NERC TPL-001-4 standard. The results of this assessment are summarized in Section 5.1 (Page 48). This study uses normal operating procedures as illustrated by transfers, phase shifter settings and normal shunt compensation settings. Transfers are as shown in Section 3.1.9 (Page 21). Note that while firm transfers are not explicitly modeled or used in New England the system conditions used in this study are sufficiently stressed to ensure that reasonably expected transfer conditions across interfaces are being tested. The study includes reactive resources as shown in Section 10 Appendix D (Page 123). Long term planning studies consider 90/10 forecasts, stressed dispatches and line out conditions and the use of these assumptions historically provide sufficient operating margins to permit the performance of maintenance activities without jeopardizing the reliability of the system.

Section 16
Appendix J: Summary of Results

See Section 5.1 of the report.

Section 17

Appendix K: Base Case Load Flow Plots

Table 17-1 List of Base Case Load Flow Plots (w/ Links)

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CATHERINE J. KEUTHEN
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June 3, 2015

Stephen H. August, Presiding Officer
Energy Facilities Siting Board
One South Station
Boston, MA 02110

Re: Eversource Energy, EFSB 15-03/D.P.U. 15-64/15-65

Dear Mr. August:

On May 20, 2015, NSTAR Electric Company d/b/a Eversource Energy (the "Company") filed a petition pursuant to G.L. c. 164, § 69J seeking approval from the Energy Facilities Siting Board to construct, operate and maintain a new 115-kV underground transmission line through the municipalities of Woburn, Winchester, Medford, Somerville, Boston and Everett and to make modifications to two existing Eversource substations, Woburn Substation and Mystic Substation ("Section 69J Petition").

With its Section 69J Petition, Eversource submitted as Appendix 2-1 a version of the Greater Boston Area Updated Transmission Needs Assessment dated January 30, 2015, that contained confidential critical energy infrastructure information ("CEII"). The Company indicated that it was in the process of developing a redacted version of that Appendix and would file that redacted document publicly when it was available. Accordingly, the Company herewith files a public, redacted version of Appendix 2-1 to its Section 69J Petition for inclusion in the public record. In addition, to facilitate public inspection of these materials, the Company will be providing this public version of Appendix 2-1 to the town clerks offices that were originally served with the Company's Section 69J Petition. The Company will also include the public version of Appendix 2-1 with its petitions made available at the specified libraries prior to the public comment hearing.

Thank you for your attention to this matter.

Very truly yours,

Catherine Keuthen

Catherine Keuthen

Enclosures

cc: Mark Marini, Department of Public Utilities (w/o att.)
Andrew Greene, Director, Siting Division (w/o att.)
James Buckley, General Counsel, Siting Division (w/o att.)

APPENDIX 2-2

Greater Boston Preferred Solution
Planning Advisory Committee (February 18, 2015)

(CEII Redacted)

FEBRUARY 18, 2015 | WESTBOROUGH, MA

Greater Boston Preferred Solution

Planning Advisory Committee

Brent Oberlin

DIRECTOR, TRANSMISSION PLANNING

Purpose

- Review the latest solution alternatives for the AC and HVDC Plans, discuss the cost and project attributes of each plan and select a preferred solution

Major Takeaway from the December PAC meeting

- The common theme discussed at the December PAC meeting was an urgent need for ISO New England (ISO-NE) to select an alternative so that siting and construction can begin as soon as possible
- ISO-NE has taken the additional information provided in December into account and has also worked with the transmission owners to gain a greater understanding of each alternative, as necessary
- ISO-NE is prepared to select a preferred solution for the Greater Boston study today

Agenda

- History of the Greater Boston study
- Discussion of the solution alternatives and cost estimates
- Transmission Owners' perspectives on the alternatives
- Cost containment proposal evaluation
- Selection of the preferred solution

HISTORY

Study History Summary

- The Greater Boston study has gone to the PAC 15 times
  - Details of some of the major PAC presentations can be found in the Appendix
- The geographic map of the study area and links to all the PAC presentations can be found in the Appendix to this presentation

Original Needs Presented in December 2009 - Updated at the July 2013 PAC Meeting

- Peak load results show numerous thermal overloads and low-voltage violations for N-1 and N-1-1 conditions
  - Critical load level was calculated for the thermal overloads and several of these violations could occur at current (2014 or earlier) load levels if the studied conditions were to materialize. The region has been exposed to some of these violations since pre-2013
- Minimum load N-1-1 testing demonstrated high voltages on the downtown Boston cable systems
- Short-circuit results showed over-dutied circuit breakers at two stations and heavily-dutied breakers (between 95% - 100%) at five stations

THE SOLUTION ALTERNATIVES

Solution Alternative Objective and Process

- The primary objective of the Greater Boston Solutions Study is to develop the most cost-effective transmission solution that meets the needs identified in the 2023 Needs Assessment
- Process
  - Began with the 2023 Needs Assessment base cases
  - Developed an AC Plan based on the preferred plan presented in March 2012
    - Tested whether all the components are still needed and incorporated any modifications to reduce the cost of the plan
  - Developed the HVDC Plan
    - Started with the HVDC line and added upgrades to complete the hybrid HVDC plan with AC components
- The result is a set of upgrades common to all plans and some unique upgrades in the AC Plan and the HVDC Plan (See the Appendix for a list and map of all common upgrades)

Solution Alternative Process

- The solutions to the needs in the Greater Boston area have been developed under the Tariff language found in Attachment K
  - As ISO-NE has been doing for many years, ISO-NE works with TOs and stakeholders to develop several alternative solutions to consider and then compares those alternative solutions
  - Then ISO-NE selects the most cost-effective solution, which then will be regionally supported

Previously Approved Upgrades

- To address pressing reliability concerns, several upgrades were presented and advanced at previous PAC meetings
- Reconductor the following:
  - 320-507 / 508 Lexington – Waltham 115 kV
  - 128-518 / P-168 Chelsea – Revere 115 kV
  - B-154N, C-155N, S-145, T-146 and portions of the Y-151 in response to the Salem Harbor NPR
  - C-129N / 201-502 Depot St. Tap – Medway 115 kV
  - D-130 / 201-501 Depot St. Tap – Medway 115 kV
  - 211-508 Woburn – Burlington 115 kV
- Add 115 kV capacitors at Hartwell and Chelsea

Upgrades Common to Both AC and HVDC Plans

- Both plans require a common set of upgrades that totals $221M which is included in the Appendix[1]
- Additionally the two plans require similar upgrades, but they are not identical in terms of configuration and/or required ratings, therefore the cost estimates are different for the two plans for these three solution components

AC Plan			HVDC Plan		
	Length (Miles)	Cost (in 2017$)		Length (Miles)	Cost (in 2017$)
2nd Mystic 345/115 kV Autotransformer	N/A	$32.2M	2nd Mystic 345/115 kV Autotransformer	N/A	$28.1M
New Mystic – Chelsea 115 kV underground cable	1	$53.4M	New Mystic – Chelsea 115 kV underground cable	1	$55.6M
Replace Woburn 345/115 kV Autotransformer and Woburn Reconfiguration	N/A	$38.8M	New Woburn 345/115 kV Autotransformer and Woburn Reconfiguration	N/A	$37.4M
Total Transmission Owner's Cost Estimate for Additional Common Plans		**$124.4M**	**Total Transmission Owner's Cost Estimate for Additional Common Plans**		**$121.1M**

---

[1] There are four projects where ISO-NE is still awaiting cost estimates

Major Unique AC Plan Upgrades

Proposed Facilities	Length (Miles)	Cost (in 2017$)
North – New Scobie – Tewksbury 345 kV	25	$122.9M
North – Reconductor Y-151 from NU[2]/NGRID border to Dracut Junction	9	
North – New Wakefield – Woburn 345 kV XLPE cable plus two 345 kV shunt reactors	8	$107.3M
North - Reconductor F-158S Maplewood – Everett 115 kV	3	$3.7M
North - Reconductor M-139 Billerica – Pinehurst 115 kV	3	$4.4M
North - Reconductor N-140 Tewksbury – Pinehurst 115 kV	7	$8.8M
North - Reconductor M-139/211-503 and N-140/211-504 115 kV lines Pinehurst – North Woburn tap	5	$6.3M
Downtown – Bifurcate a new Woburn – Mystic 115 kV cable and existing cable	8	$75.0M
Downtown - Open the Mystic 115 kV downtown ties	N/A	$0.3M
Downtown - Close the 115 kV bus tie breakers and add a series 115 kV breaker at K Street	N/A	$2.6M
Western - Upgrade the 533-508 Lexington – Hartwell 115 kV terminal equipment	N/A	$0.4M
All locations – Upgrade 5 substations to BPS standards	N/A	$36.6M
ME – Add a 200 MVAR STATCOM (**based on 2014 dollars**)	N/A	$26.0M
Total Transmission Owner's Cost Estimate for AC Upgrades		**$394.3M**

---

[2] Northeast Utilities (NU), which includes PSNH and NSTAR, has recently changed its name to Eversource Energy. Northeast Utilities is used in this presentation for consistency with past Greater Boston presentations.

Common Upgrades

AC Plan Upgrades

One-line of the AC Plan Upgrades

The 200 MVAR STACOM in ME is not shown

[redacted]

Major Unique HVDC Plan Upgrades

Proposed Facilities	Length (Miles)	Cost (in 2017$ unless otherwise noted)
North – New Seabrook – Mystic 520 MW HVDC cable, two terminals and interconnection at Mystic 115 kV – **The cost estimates for the HVDC line ($543.0M) and the Seabrook interconnection ($31.7M) total $574.7M and are estimated in 2018 dollars**	68	$604.6M
North - Additional upgrade to the Y-151 115 kV (larger conductor) from NU/NGRID border to Dracut Junction	9	$16.6M
North - Reconductor 337 Sandy Pond – Tewksbury 345 kV	16	$46.4M
Downtown - Bifurcate the Mystic – North Cambridge 345 kV cables	N/A	$12.5M
North - Add Sandy Pond 345 kV breaker	N/A	$3.2M
Downtown – Upgrades to address 250-516/517 overloads – **will not be substantial when compared to the HVDC Plan's total cost**		**Not yet provided**
Total Transmission Owner's Cost Estimate for AC Upgrades		**$683.3M**

Common Upgrades

HVDC Plan Upgrades

One-line of the HVDC Plan Upgrades

[redacted]

Transmission Owners' Cost Estimates

AC Plan	**Cost (in 2017$ unless otherwise noted)**	**HVDC Plan**	**Cost (in 2017$ unless otherwise noted)**	**Delta ($M)**
Common Upgrades (See Appendix for projects and cost estimates)	A $221.0M	Common Upgrades (See Appendix for projects and cost estimates)	D $221.0M	$0
Additional Common Upgrades	B $124.4M	Additional Common Upgrades	E $121.1M	-$3.3M
		AC projects in the HVDC Plan – **$31.7M estimated in 2018 $**	F $140.3M	
		HVDC Line Only – **estimated in 2018$**	G $543.0M	
Major Unique AC Plan Upgrades – **cost of the STATCOM in ME ($26.0M of the $394.3M) is estimated in 2014$**	C $394.3M	Major Unique HVDC Plan Upgrades (F + G)	$683.3M	$289.0M
Total Transmission Owners' Cost Estimates (A + B + C)	**$739.7M**	**Total Transmission Owners' Cost Estimates (D + E + F + G)**	**$1,025.4M**	**$285.7M**

Independent Consultant Review of Project Cost Estimates

- Electrical Consultants, Inc. (ECI) was hired to develop conceptual cost estimates for the design, engineering, construction and commissioning of the 11 projects based on project scope information provided from the transmission owners
- The 11 projects are:

Selected Major Unique AC Plan Components	Selected Major Unique HVDC Plan Components
New Scobie – Tewksbury 345 kV	New Seabrook – Mystic 520 MW HVDC cable with two terminals
Reconductor Y-151 from NU/NGRID border to Dracut Junction	Seabrook 345 kV interconnection for HVDC
New Wakefield – Woburn 345 kV XLPE cable add two 345 kV shunt reactors	Mystic 115 kV interconnection for HVDC
Bifurcate a new Woburn – Mystic 115 kV cable and existing cable	Upgrade the Y-151 115 kV from NU/NGRID border to Dracut Junction
200 MVAR STATCOM at Coopers Mills station in ME	Reconductor 337 Sandy Pond – Tewksbury 345 kV
	Bifurcate the Mystic – North Cambridge 345 kV cables

Independent Consultant Review of Project Cost Estimates[3], cont

Selected Major Unique AC Plan Components	TO	ECI 2017[4] Dollar Cost Estimate	TO 2017[5] Dollar Cost Estimate	Delta ($M / %)
Scobie – Tewksbury 345 kV and Y-151 Reconductor	NU/NGRID	$132.3M	$101.6M	$30.7M / 30.2%
Wakefield – Woburn 345 kV UG cables plus 345 kV shunt reactor	NU	$93.5M	$80.3M	$13.2M / 16.4%
Wakefield – Woburn 345 kV UG cables plus [illegible] kV shunt reactor	NGRID	$14.8M	$16.3M	-$1.5M / -9.2%
Bifurcate a new Woburn – Mystic 115 kV cable with the existing cable	NU	$73.9M	$69.1M	$4.8M / 6.9%
200 MVAR STATCOM at Coopers Mills station in ME	CMP	$40.4M[6]	$27.9M[6]	$12.5M / 44.8%
Totals		**$354.9M**	**$295.2M**	**$59.7M / 20.2%**

[3] The details of the independent consultant review from the November 18, 2014 PAC meeting. http://www.iso-ne.com/static-assets/documents/2014/11/a4_eci_greater_boston_solutions_presentation.pdf

[4] The ECI cost estimate was escalated from 2014 to 2017

[5] All contingency was removed from the TO cost estimate and any costs not in 2017 dollars were escalated/deescalated to 2017 dollars

[6] The TO estimate was escalated from 2014 to 2017 dollars and ECI's estimate was escalated from 2015 to 2017 dollars

Independent Consultant Review of Project Cost Estimates

Selected Major Unique HVDC Plan Components	TO	ECI 2017 [7] Dollar Cost Estimate	TO 2017 [8] Dollar Cost Estimate	Delta ($M / %)
HVDC submarine cable and two terminals	NHT	$534.6M	$519.0M	$15.6M / 3.0%
Seabrook 345 kV interconnection for the HVDC	NHT	$30.4M	$28.9M	$1.5M / 5.2%
Mystic 115 kV interconnection for the HVDC	NU	$27.0M	$27.6M	-$0.6M / -2.2%
Reconductor Y-151	NGRID	$11.3M	$13.2M	-$1.9M / -14.4%
Reconductor Sandy Pond – Tewksbury 345 kV	NGRID	$36.9M	$36.7M	$0.2M / 0.5%
Bifurcate Mystic – North Cambridge 345 kV	NU	$15.8M	$11.5M	$4.3M / 37.4%
Totals		**$656.0M**	**$637.0M**	**$19.0M / 3.0%**

[7] The ECI cost estimate was escalated from 2014 to 2017

[8] All contingency was removed from the TO cost estimate and any costs not in 2017 dollars were escalated/deescalated to 2017 dollars

Independent Consultant Review of Project Cost Estimates - Summary

Selected Major Unique Plan	ECI 2017 Dollar Cost Estimate	TO 2017 Dollar Cost Estimate	Delta ($M / %)
AC Plan	$354.9M	$295.2M	$59.7M / 20.2%
HVDC Plan	$656.0M	$637.0M	$19.0M / 3.0%

- The results show the TO's cost estimates are viable based on the independent consultant's analysis and fall well within the Planning Procedure 4, Attachment D accuracy of +50% / -25% for the 11 proposed projects
- When ECI's cost estimates for the 10 projects (Excludes ECI estimate for STATCOM in ME) are used with the TO's cost estimates excluding contingency costs, the difference in cost between the HVDC Plan and AC Plan is $257.7M[9]
- Since the November PAC presentation, ECI has estimated the cost for the STATCOM in ME and taking this into account would narrow the gap between the two plans by $12.5 M to $245.2 M

[9] http://www.iso-ne.com/static-assets/documents/2014/12/a4_greater_boston_solution_study_cost_comparisons.pdf

NHT COST CONTAINMENT PROPOSAL

NHT Cost Containment Proposal

- NHT commits that it would exclude capital costs that are more than 25% above its current estimate of $543M for the HVDC portion only, or $679M, from its rate base. The majority of the project would not be covered by the containment proposal. The cost cap thus limits cost overruns for the HVDC section only to $136 million over NHT's estimate
- NHT commits that it would only earn the New England base return on equity (ROE) on any HVDC Plan costs that exceed $543M and up to the capped amount of $679M
- NHT commits to exclude $20M of HVDC Plan capital costs from its rate base if the project is not in service by December 31, 2018 as long as ISO-NE selects the HVDC Plan as the preferred alternative by February 2015
- Since cost containment is not part of the existing tariff, this proposal would only be in effect if filed with and approved by the FERC

Cost Containment Cost Evaluation

- NHT's cost containment proposal only applies to the HVDC portion

AC Plan			HVDC Plan			
	Cost (from Slide 17)	Cost + 50%		Cost (from Slide 17)	Cost + 50%	Cost + 25%
Common Upgrades	$221.0M	A $331.5M	Common Upgrades	$221.0M	D $331.5M	N/A
Additional Common Upgrades	$124.4M	B $186.6M	Additional Common Upgrades	$121.1M	E $181.7M	N/A
Major Unique AC Plan Upgrades	$394.3M	C $591.5M	Major Unique HVDC Plan Upgrades - AC projects	$140.3M	F $210.5M	N/A
			Major Unique HVDC Plan Upgrades - HVDC projects	$543.0M	G $814.5M	H $679.0M
			HVDC Plan (Cost + 50%) Subtotal No Cost Containment (D + E + F + G)		$1,538.2M	
AC Plan (Cost + 50%) Subtotal (A + B + C)		**$1,109.6M**	**HVDC Plan {(AC Portion Cost + 50%) + (HVDC Portion Cost + 25%)} Subtotal Includes Cost Containment (D + E + F + H)**		**$1,402.7M**	

Cost Containment Proposal Delta Difference between the HVDC and AC Plans = $293.1M

- The cost containment proposal only reduces the worst case cost scenario by $135.5M ($1,538.2M - $1,402.7M)
- Because the HVDC Plan is much more expensive and the cost cap is established by using a factor of 1.25, the AC Plan remains less expensive even when accounting for significant cost overruns

Potential Cost Outcomes Analysis - Cost Estimate Delta between Plans

Potential Cost Outcomes	HVDC Plan	AC Plan	Delta (HVDC – AC)
Scenario 1 – Actual costs match estimate	Cost Estimate $1,025.4M	Cost Estimate $739.7M	$285.7M
Scenario 2 – Actual costs at high end of estimate accuracy (+50%)	Cost Estimate + 50% $1,538.2M	Cost Estimate + 50% $1,109.6M	$428.6M
Scenario 3 – Actual costs respecting Cost Cap proposal for the HVDC line and 50% for all other components	(HVDC line cost estimate + 25%) + (All other HVDC Plan cost estimate + 50%) $1,402.7M	Cost Estimate + 50% $1,109.6M	$293.1M
Scenario 4 – Actual costs using the estimate for HVDC line and 50% for all other components	HVDC Cost Estimate + (All other HVDC Plan cost estimate + 50%) $1,266.7M	Cost Estimate + 50% $1,109.6M	$157.1M

- There is no scenario in which ISO-NE would expect the HVDC Plan to be cost competitive with the AC Plan

COMPARISON OF PLANS FROM THE TRANSMISSION OWNER PERSPECTIVE

Comparison of Plans from the transmission owner perspective

NHT	NU/NGRID
Scobie to Tewksbury 345 kV line cannot be built without taking new land, reconfiguring the existing right of way or creating double circuit towers	There are portions of Scobie to Tewksbury 345 kV line which will require the existing right of way to be reconfigured, however no additional land is needed and no double circuit towers will be created
When comparables (similar projects recently completed) are taken into consideration, the NU/NGRID cost estimates are hundreds of millions of dollars below actual comparables. NU/NGRID's cost estimates are being under estimated	The comparables used by NHT for overhead 345 kV construction are for projects that were more complex to construct because they had more intricate right of way (ROW) reconfiguration (4 structures on the majority of ROW) and 75% of the circuits needed vertical monopole construction which is more expensive. With respect to UG construction NU/NGRID's estimate of $7.8M a mile is comparable to the $8.0M a mile estimate provided by NHT for the UG land potion of HVDC Plan. Also, recent quotes from XLPE cable vendors are lower than in 2008 (when the last major 345 kV UG cable additions were made) since oil and copper prices are lower. NU/NGRID stand by the accuracy of their cost estimates
When comparables (similar projects recently completed) are taken into consideration, the NU/NGRID in-service dates are understated by 2 to 3 years in some cases. A faster in-service date affects the reliability and cost to customers	NU/NGRID stand by their estimated in-service dates of December 2017 for their projects reported in the October 2014 Project Listing

Comparison of Plans from the transmission owner perspective, cont

NHT	NU/NGRID
The HVDC project is more storm resilient because the majority of the new facilities will be undersea and won't be subjected to extreme weather or tree contact	345 kV line forced outages are rare and quickly repaired. The October 2011 snow storm resulted in only one 345 kV outage due to tree contact and did not result in any customer outages. Undersea cable failures are less frequent however repairs could take months and are more costly than AC overhead repairs
The HVDC Plan has less permitting risk than the AC Plan	Comparable HVDC projects in other parts of the country have had permitting durations from 25 to 45 months. Both plans have to go before 10 agencies for reviews, licenses or permits. The HVDC Plan has to go before an additional 7 agencies while the AC Plan only needs to go before 2 agencies. The HVDC Plan will need to coordinate the construction with marine life time of year restrictions

Comparison of Plans from the transmission owner perspective, cont

NHT	NU/NGRID
Through their consultant, The Brattle Group, NHT claims that AC Plan will cost an additional $163M due to the higher cost of electricity during construction and would require certain critical lines to be out of service for seven months. In addition, the AC Plan will cost an additional $349M if the AC Plan is delayed one year due to permitting issues. Under any of these scenarios, the HVDC Plan is more cost-effective project for customers	NU/NGRID would be flexible in scheduling outages during shoulder months to minimize congestion costs. The Scobie to Tewksbury 345 kV line construction schedule only requires multiple short duration outages and a 3 week outage which potentially contribute to congestion costs in the thousands of dollars not millions of dollars. ISO-NE Operations has analyzed NU/NGRID's proposed outage schedule and they concluded there would not be any significant congestion costs. NHT fails to consider any congestion costs for their work to reconductor the Sandy Pond – Tewksbury 345 kV line. NGRID estimates many daily outages along with two 6 week outages. This project has the potential to create out-of-merit generation commitment

THE SELECTION OF THE PREFERRED SOLUTION ALTERNATIVE

The Selection of the Preferred Solution Alternative

- Typically, ISO-NE has selected the solution alternative which has the lowest cost estimate and fully addresses the identified reliability needs unless the cost estimates of competing solution alternatives have been similar. In these situations, ISO-NE would consider other criteria to evaluate other benefits to the transmission system that the competing solution alternative may bring. After careful consideration, ISO-NE would select the most cost effective solution alternative

The Selection of the Preferred Solution Alternative, cont

- In this case, the cost estimates for the AC and HVDC plans are hundreds of millions of dollars apart. In cases such as this, ISO-NE would typically conclude its review on this basis. However, as requested by the stakeholders, ISO-NE evaluated the merits of each plan by considering other criteria which includes but is not limited to:
    - Constructability
    - Construction outage requirements/cost impacts
    - Expected in-service dates
    - Interface impacts
    - Losses
    - Extreme contingency analysis results
    - Expansion capabilities
    - Lifetime maintenance requirements
    - Incremental costs for potential retirements
    - Siting issues
    - Storm hardening
    - Operational performance

Constructability

- NHT has conducted both marine and land surveys and have the confidence that their upgrade plans can be executed
- NU/NGRID have demonstrated at the December PAC and meetings with ISO-NE that the Scobie Pond to Tewksbury 345 kV line can be constructed without expansion of the existing right of way, without taking any homes along the right of way and doesn't require any double circuit towers (DCTs)
- ***ISO-NE's position is both plans are constructible***

Construction Outage Requirements/Cost Impacts

- NU/NGRID have demonstrated at the December PAC and meetings with ISO-NE that outages associated with construction for the AC Plan are not expected to be significant
  - Extensive ROW reconfiguration is needed for only a small portion of the ROW (0.5 miles)
  - Outage durations are short – longest outage is a three week period
  - Outages are flexible and can be scheduled during the shoulder months or during generator annual inspections
- NHT's HVDC Plan has the potential for significant generation reductions or outages that could result in congestion costs
  - More extensive work required at the Mystic 115 kV Station (Discussed in the following slides)
  - Seabrook 345 kV Station
  - Sandy Pond – Tewksbury 337 Line (345 kV) Reconductoring
- Outage information and potential congestion concerns have been discussed with ISO-NE Operations
- ***ISO-NE's position is the AC Plan will not significantly contribute to congestion costs and more analysis would be needed to determine the congestion cost impact of the HVDC Plan***

Comparison of Impact at Mystic

<table>
<tr><th colspan="2">Upgrades Common to Both AC and HVDC Plans</th></tr>
<tr><td colspan="2">• Add a new 345/115 kV autotransformer at Mystic
• Add a new 115 kV line that connects to the GIS portion of the Mystic 115 kV bus</td></tr>
<tr><th>AC Plan</th><th>HVDC Plan</th></tr>
<tr><td>• Relocate a 345 kV line at Mystic 345 kV
• Swap terminations of two 115 kV lines on the GIS portion of the Mystic 115 kV bus</td><td>• Relocate a 345 kV line at Mystic 345 kV to the location of an existing 345 kV line (Requires outages on both 345 kV lines)
• Relocate a 115 kV line from the GIS portion of the bus to the open air portion of Mystic 115 kV
• Interconnect the HVDC line to one of the buses via an existing breaker
• Relocate two 115 kV breakers, one of which is connected to one of the Mystic block 9 gas turbines
• Add two bus sections to connect the GIS portion of the Mystic 115 kV bus to the open air portion of the Mystic 115 kV bus
• Relocate two distribution transformers at Mystic 115 kV which includes the addition of a new 115 kV breaker</td></tr>
</table>

Mystic Configuration - Existing

Mystic Configuration – AC Plan

[redacted]

Mystic Configuration – HVDC Plan

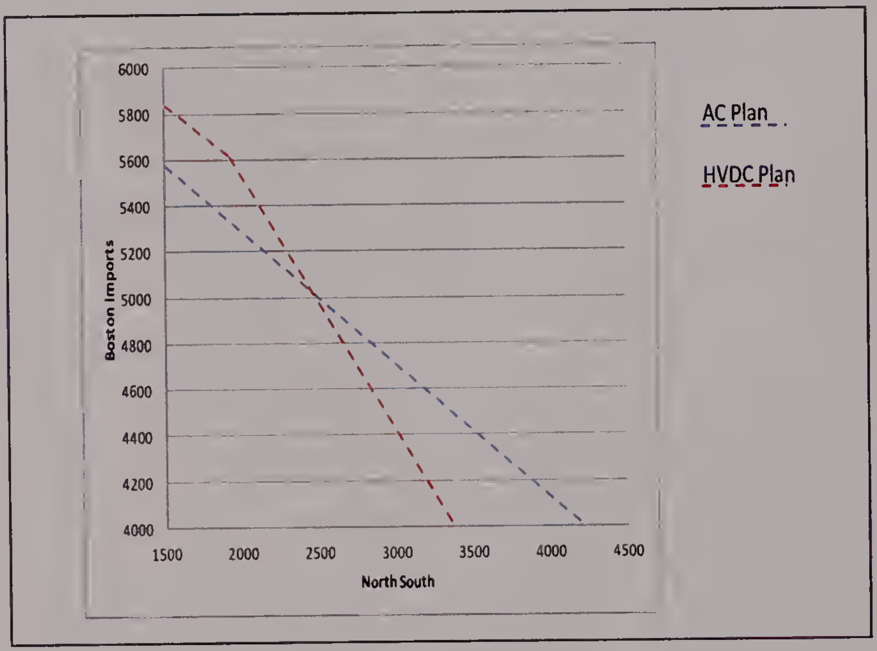
Expected In-service Dates

- Once through siting, both plans can be in-service in a reasonable amount of time
- All entities involved, NHT, NU and NGRID have expressed confidence in meeting their proposed in-service dates
- Both plans, as per the information provided to ISO-NE, have a final in-service date in 2018
- ***ISO-NE does not believe that one plan would have a substantially earlier in-service date over the other plan***

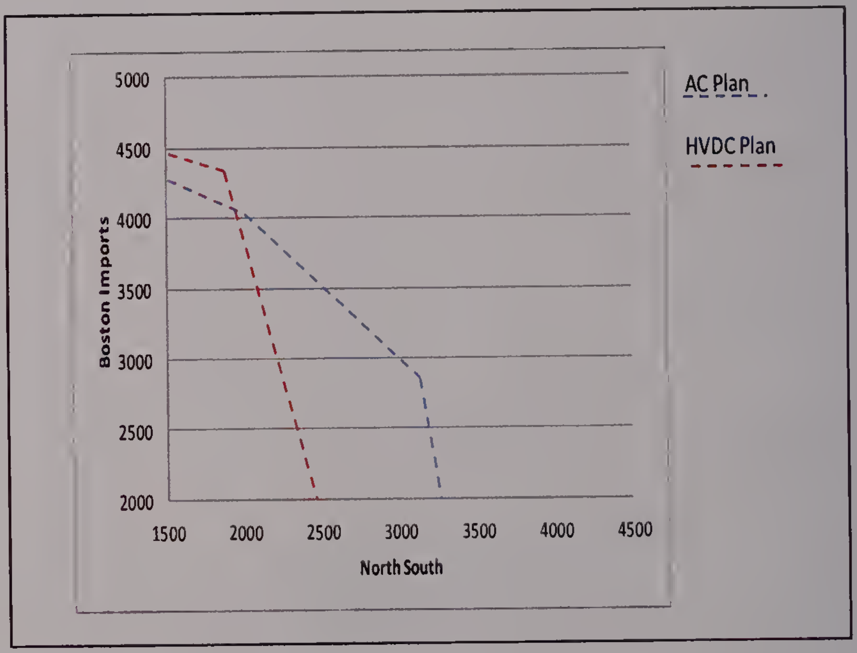
Interface Impacts

- The Greater Boston Working Group (GBWG) performed an N-1 and N-1-1 assessment on the Boston Import versus North/South for both plans

N-1



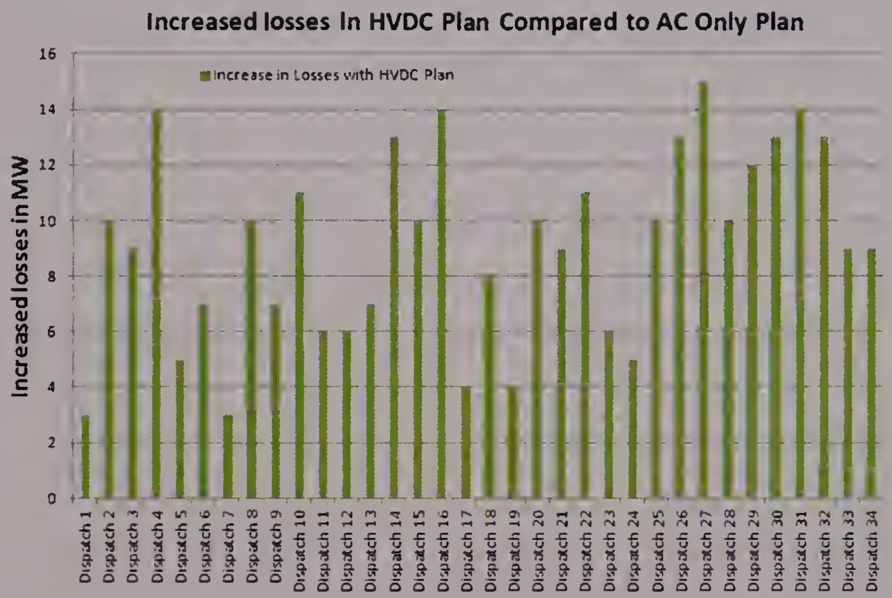
N-1-1



- Both plans result in a comparable increase in the N-1 Boston import transfer capability
- The AC Plan provides higher N-1-1 Boston Import transfer capability at higher levels of North / South transfers
  - The higher levels of North / South transfers may not be achievable due to Northern New England-Scobie+ 394 interface limits
- ***ISO-NE's position is that both plans improve the Boston Import transfer capability, but the AC plan could potentially provide improved N-1-1 performance if the Northern New England-Scobie+394 interface limit was increased***

Losses

- The basecases that were used for the peak load analysis were reviewed for system losses across New England
- The New England system total losses varied from 600 to 700 MW
- The HVDC plan had losses between 3 to 15 MWHr/Hr more than the AC plan



- ***ISO-NE's position is the AC Plan results in slightly lower system losses compared to the HVDC plan***

Extreme Contingency (EC) Analysis Results

- A screening analysis was performed for a limited set of extreme contingencies:
  - Line crossings
  - Loss of lines in a common right of way (ROW)
  - Loss of a substation
- All the line crossing contingencies showed no overloads or voltage violations for both plans
- For the loss of ROW and loss of substation contingencies the HVDC plan resulted in fewer violations
- ***ISO-NE's position is the HVDC Plan resulted in better extreme contingency performance***

Expansion Capabilities

- The following summarizes the highest short circuit duties at stations post project:

Station Name	AC Plan	HVDC Plan
Mystic 115 kV	86%	85%
Kingston 115 kV	88%	95%
K Street 115 kV	88%	90%

- The AC Plan provides benefit in terms of available short circuit margin for future transmission and generation additions
- The future expansion of the HVDC system would be costly
  - To interconnect a resource into an HVDC facility, a new terminal needs to be installed, a significant expenditure (Note that approximately 50% of the HVDC Line cost is for two land-based terminals)
  - As time progresses the ability to procure additional terminals whose technology can work in concert with the existing terminals becomes more difficult
  - May require the additional terminals to be procured by the same manufacturer to ensure functionality
- ***ISO-NE's position is the AC Plan provides better expansion capabilities than the HVDC Plan***

Lifetime Maintenance Requirements

- ISO-NE's prior experience with HVDC and FACTS technology suggests that with technological advances in state-of-the-art equipment in the future, there will be a need for costly upgrades:
  - Highgate HVDC facility needed a $38M refurbishment upgrade in 2012[10]
  - Chester SVC needed a $6M control system upgrade in 2013[11]
- HVDC plan has both larger sized equipment and two locations where such upgrades might be necessary
  - HVDC Plan requires two 520 MW HVDC terminals
  - AC Plan requires a 200 MVAR STATCOM in ME
- ***ISO-NE's position is the AC Plan provides better lifetime maintenance requirements than the HVDC plan***

[10] https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2011/feb162011/highgate.pdf
[11] https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/jan182012/chester_svc.pdf

Incremental Costs for Potential Retirements

- The GBWG tested the AC and HVDC plans on a Mystic 7 retirement scenario to determine additional upgrades needed

AC Plan

	Length (miles)	Cost (in 2017$)
New Mystic – K St. 345 kV Cable	6.8	$94.5M
345 kV Phase Angle Regulator at K. St.	N/A	
160 MVAR Shunt Reactor at K. St.	N/A	
Series Reactor on the Stoughton – K St. 3162 Cable	N/A	$4.7M
Re-conductor M-139 115 kV Pinehurst to N. Woburn Tap	0.6	$3.2M
Re-conductor N-140 115 kV Pinehurst to N. Woburn Tap	0.6	$3.2M
Total		$105.6M

ISO-NE's position is that while the costs of both expansion plans are similar, the cost for the AC Plan is less expensive

HVDC Plan

	Length (miles)	Cost (in 2017$)
New Golden Hills – Woburn 345 kV Cable	6.5	$88.4M
160 MVAR Shunt Reactor at Woburn	N/A	
Re-conductor F-158N Golden Hills – Maplewood 115 kV (larger conductor	4.0	$4.5M
Re-conductor F-158S 115 kV Maplewood to Everett	3.0	$3.8M
Re-conductor S-145 Wakefield to N. Reading Tap	5.6	$3.6M
Re-conductor T-146 Wakefield to N. Reading Tap	5.6	$3.6M
Upgrade West Medway 345/115 kV auto	N/A	$7.9M
Re-conductor E-157 Millbury to Centech	5.7	$6.4M
Total		$118.2M

Siting Issues

- ISO-NE does not take the complexity in siting a particular alternative into account unless the costs for the alternatives under consideration are similar
  - As an example, ISO-NE did not support the regional cost allocation of underground cables in the Middletown-Norwalk and Bethel-Norwalk Project
- Applicable guidance from the tariff and ISO-NE Planning procedures are as follows:
  - Attachment K, Section 4.2(b) states:
    - "Through this process, the ISO may identify the most cost-effective and reliable solutions for the region that meets a need identified in a Needs Assessment. These solutions may differ from a transmission solution proposed by a transmission owner."

Siting Issues, cont.

- PP-4, Attachment A states:
  - "The following…is provided for illustration of the types of projects that would be considered to contain Localized Costs: The Project includes underground transmission cable, which is selected (a) at the direction of a local or state siting board, or (b) to address other local concerns, and the cost of overhead transmission lines is less expensive, taking into account all relevant costs.
- PP-4, Section 1.6.1(C)3(i) states:
  - "The proposed Project, and any feasible and practical transmission alternatives that were considered, including those offered in the most recent RSP report and, if applicable, discussed at the PAC. Note - A feasible and practical transmission alternative means a transmission alternative that is feasible and practical from an engineering design and construction perspective. An alternative that is not or may not be approved by a siting or local review board may still be considered a feasible and practical transmission alternative."

- ***ISO-NE's position is that both AC and HVDC plans are feasible from an engineering perspective and siting is not a determining factor***

Storm Hardening

- The majority of the HVDC Plan consists of an buried cable which should be resistant to most storms
  - Cable failures may require a month or more to repair
- The AC Plan is more exposed to the environment than the HVDC Plan
  - Overhead line repairs are generally made within a day or two
- History has shown that buried cables are not impervious to storm interruption because their terminals are still exposed
- ***ISO-NE's position is that the HVDC plan has less exposed facilities, yet the time required to repair such facilities causes the ISO to view the AC and HVDC plans as equal***

The Selection of the Preferred Solution Alternative - Summary

Selection Criteria	AC Plan	HVDC Plan
Cost	✓	✗
Constructability	✓	✓
Construction outage requirements/cost impacts	✓	✗
Expected in-service dates	✓	✓
Interface impacts	✓	✗
Losses	✓	✗
Extreme contingency analysis results	✗	✓
Expansion capabilities	✓	✗
Lifetime maintenance requirements	✓	✗
Incremental costs for potential retirements	✓	✗
Siting issues	✓	✓
Storm hardening	✓	✓

✓ Is applied to the Alternative which better achieves the objective

✗ Is applied to the Alternative which does not achieve the objective as well as the other competing Alternative

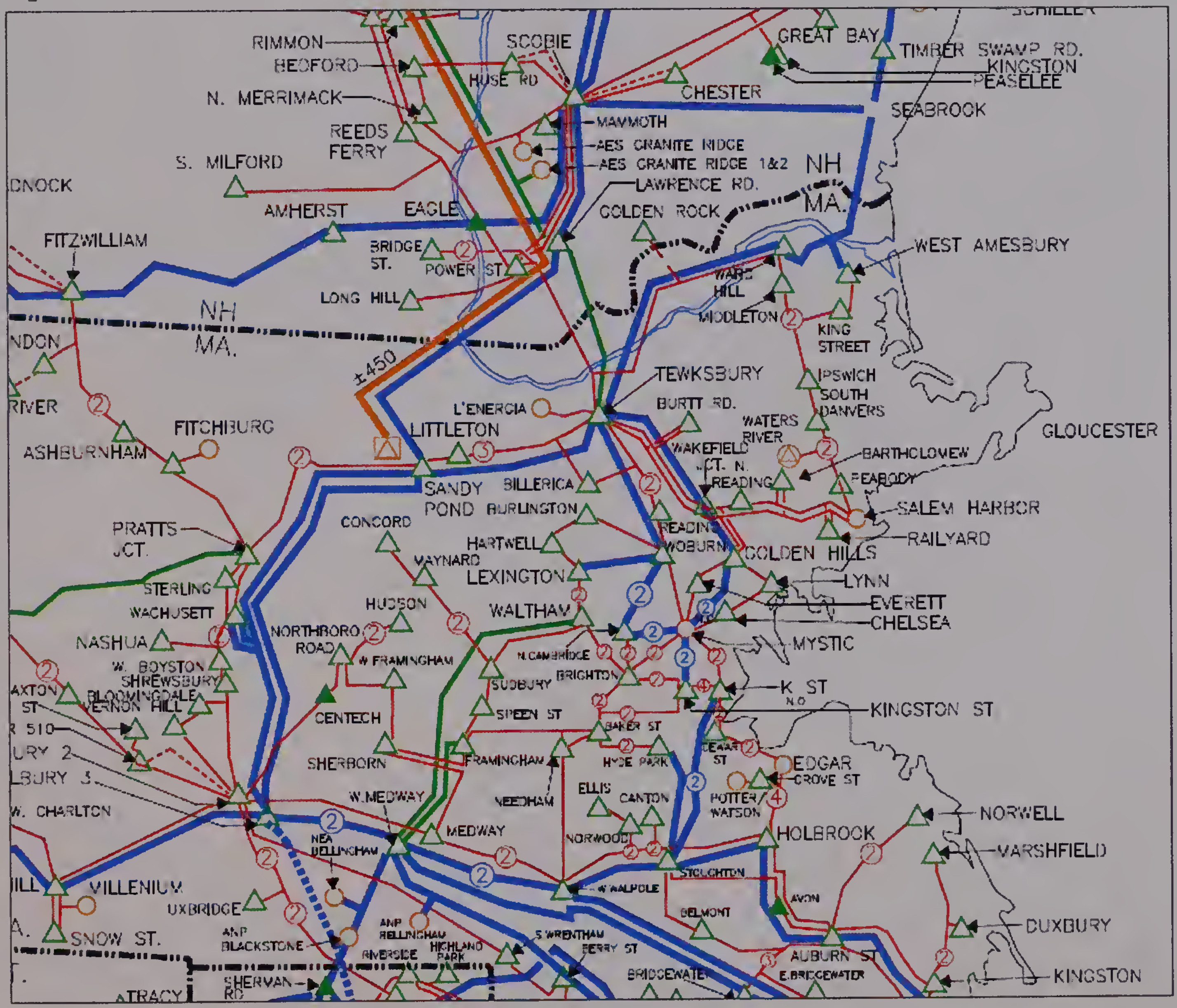
The Selection of the Preferred Solution Alternative

- Based on the factors discussed, the cost separation between the two plans is still wide even after considering other criteria
- The AC Plan is the most cost effective solution for the region and the AC Plan is the preferred solution alternative for the Greater Boston study

Questions

APPENDIX

Geographical Map of the Study Area


RIMMON
BEDFORD
N. MERRIMACK
SCOBIE
HUSE RD
REEDS FERRY
S. MILFORD
AMHERST
EAGLE
CHESTER
GREAT BAY
TIMBER SWAMP RD.
KINGSTON
PEASELEE
SEABROOK
MAMMOTH
AES GRANITE RIDGE
AES GRANITE RIDGE 1&2
LAWRENCE RD.
NH
MA.
GOLDEN ROCK
FITZWILLIAM
BRIDGE ST.
POWER ST
LONG HILL
WEST AMESBURY
WARD HILL
MIDDLETON
KING STREET
±450
TEWKSBURY
IPSWICH
SOUTH DANVERS
BURTT RD.
L'ENERGIA
LITTLETON
FITCHBURG
ASHBURNHAM
RIVER
WATERS RIVER
WAKEFIELD JCT.
N. READING
BARTHOLOMEW
PEABODY
GLOUCESTER
SANDY POND
BILLERICA
BURLINGTON
SALEM HARBOR
RAILYARD
PRATTS JCT.
CONCORD
HARTWELL
MAYNARD
READING
WOBURN
GOLDEN HILLS
LEXINGTON
LYNN
EVERETT
CHELSEA
STERLING
WACHUSETT
HUDSON
WALTHAM
NASHUA
NORTHBORO ROAD
W. FRAMINGHAM
N. CAMBRIDGE
MYSTIC
W. BOYSTON
SHREWSBURY
BLOOMINGDALE
VERNON HILL
BRIGHTON
SUDBURY
K ST
KINGSTON ST
CENTECH
SPEEN ST
BAKER ST
SHERBORN
FRAMINGHAM
HYDE PARK
CEDAR ST
EDGAR
GROVE ST
W. MEDWAY
NEEDHAM
ELLIS
CANTON
POTTER
WATSON
NORWELL
W. CHARLTON
MEDWAY
NORWOOD
HOLBROOK
MARSHFIELD
NEA BELLINGHAM
STOUGHTON
MILLENIUM
UXBRIDGE
W. WALPOLE
AVON
BELMONT
DUXBURY
SNOW ST.
ANP BLACKSTONE
ANP BELLINGHAM
RIVERSIDE
HIGHLAND PARK
S. WRENTHAM
FERRY ST
BRIDGEWATER
AUBURN ST
E. BRIDGEWATER
KINGSTON
SHERMAN RD
TRACY

Study History

- First trip to the PAC was May 2008 with a presentation of the Needs Assessment Scope of Work
- Steady state needs were presented in July 2009 (N-1) and in December 2009 (N-1-1) with a Needs Assessment report issued in July 2010
  - Short-circuit needs and critical load level assessment were presented at June 2011 PAC
- Identified and advanced some of the upgrades including five 115 kV line reconductorings needed for the Salem Harbor Non-Price Retirement (NPR) in June 2011
- A complete Greater Boston AC preferred solution was presented to PAC in March 2012
  - Agreed to examine a hybrid HVDC / AC alternative conceptual proposal made by New Hampshire Transmission, LLC (NHT)
- In July 2013 a refreshed set of needs updated to the 2013 CELT, FCA 7, and the updated NSTAR cable ratings were presented to PAC (Greater Boston 2023 Needs Assessment)
- In June 2014 two plans to meet the reliability needs of the Greater Boston area were presented to PAC
  - Revised AC Plan to meet the July 2013 refreshed needs
  - An HVDC Plan based on the NHT hybrid proposal
- In November 2014 an independent consultant provided a review of the major unique components of the AC Plan and the HVDC Plan
- In December 2014 both NHT and Northeast Utilities (NU)/National Grid (NGRID) each presented their assessment of the pros and cons of the two plans

Study History

1. Needs Assessment scope presented to PAC in May 2008

   https://smd.iso-ne.com/trans/sys_studies/rsp_docs/pres/2008/a_nema_boston.pdf

2. Initial needs presented to PAC in January 2009

   https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2009/jan212009/a_greater_boston_sow.pdf

3. Detailed preliminary needs and Notification of Solution Study discussed at PAC in July 2009

   https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2009/jul162009/boston.pdf

4. Needs Assessment Status Update in December 2009

   http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/dec162009/gbwg.pdf

Study History

5. Greater Boston Study Needs Assessment/Solution Study Status Update presented at PAC in December 2010
   - Grouped transmission solution alternatives into three areas
     - North of Boston
     - South of Boston
     - Central Area
   - Identified the preliminary preferred solutions for both the north and south areas

     https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2010/dec162010/greater_boston.pdf

Study History

6. Greater Boston Study Needs Assessment/Solution Study Status Update presented at PAC in June 2011
   - Completed the "Needs Assessment" phase by presenting short-circuit assessment and critical load level assessment for the Boston Area
   - Discussed the impact of Salem Harbor NPR

   https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2011/jun302011/greater_boston.pdf

Study History

7. Greater Boston Study Needs Assessment/Solution Study Status Update presented at PAC in January 2012
   - Grouped transmission solution alternatives for the Central Area into the Western Suburbs and Downtown Boston sub-Areas
   - Western Suburbs
     - Presented competing transmission alternatives
     - Provided feasibility, cost, and technical assessment
     - Identified the preliminary preferred solutions
   - Downtown Boston
     - Presented competing transmission alternatives

   https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/jan182012/gbwg_update.pdf

Study History

8. Greater Boston Study Needs Assessment / Solution Study Status Update in March 2012
   - Downtown Boston
     - Presented competing transmission alternatives
     - Provided feasibility, cost, and technical assessment
     - Identified the preliminary preferred solutions
   - Presented the complete Greater Boston Solution
   - Agreed to consider an HVDC alternative from Seabrook into Boston

   https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/mar142012/gbwg_update.pdf

9. Greater Boston Solution Study Update in February 2013
   - Presented the impact of assumption changes
   - Presented a preliminary transfer assessment based on the set of AC upgrades described in the March 2012 PAC presentation

   https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2013/feb122013/a5_greater_boston_solution_study_update.pdf

Study History

10. NSTAR Underground Cable Rating Update in April 2013

    https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2013/apr242013/a10_nstar_greater_boston_cable_ratings.pdf

11. Greater Boston 2023 Needs Assessment and Solution Study Status Update in July 2013

    https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2013/jul92013/a2_greater_boston_needs_assessment.pdf

12. Greater Boston 2023 Solutions Study Status Update in November 2013

    https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2013/nov202013/a6_greater_boston_2023_needs_assessment_soultion_update.pdf

Study History

13. Greater Boston Solutions Study Update in June 2014

    http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/jun192014/a4_greater_boston_solution_study_cost_estimates.pdf

14. Greater Boston Solutions Study Update and Greater Boston Solutions Study High Level Cost Estimate by ECI in November 2014

    http://www.iso-ne.com/static-assets/documents/2014/11/a4_greater_boston_solution_study_cost_comparisons.pdf

    http://www.iso-ne.com/static-assets/documents/2014/11/a4_eci_greater_boston_solutions_presentation.pdf

Study History

15. NHT’s presentation titled Greater Boston Solutions in December 2014

http://www.iso-ne.com/static-assets/documents/2014/12/a6_nht_greater_boston_presentation.pdf

NU/NGRID’s presentation titled Comparison of the AC and HVDC Solutions Greater Boston

http://www.iso-ne.com/static-assets/documents/2014/12/a6_nu_ngrid_greater_boston_presentation.pdf

16. Needs Assessment report posted on January 30, 2015

https://smd.iso-ne.com/planning/ceii/reports/2010s/greater_boston_updated_needs_assessment_report_final.pdf

Upgrades Common to Both AC and HVDC Plans

Proposed Facilities	Length (Miles)	Cost (in 2017$)
North - Reconductor Y-151 Power Street– NU/NGRID border	4	$8.5 M
North - Reconductor M-139 Tewksbury – Billerica 115 kV	3	$5.3 M
North - Reconductor F-158N Golden Hills– Maplewood 115 kV	4	$5.4 M
South - West Walpole – Holbrook 115 kV – **Project is being Advanced**	14	$17.3 M
South – Sharon Switching station – **Project is being Advanced**	N/A	$12.8 M
Western - Sudbury 230/115 kV autotransformer	N/A	$28.1 M
Western Sudbury – Hudson 115 kV – **Does not include Hudson Light & Power termination cost**	9	$46.0 M
Western - Refurbish the X-24 69 kV	15	$8.5 M
Western - Reconductor W-23W Northboro – Woodside 69 kV	6	$5.9 M
Western - Reconfigure the Waltham substation	N/A	$17.5 M
Western - Separate the X-24 / E-157W DCT	4 Structures	$3.4 M
Western - Add 36.7 MVAR capacitor at Sudbury 115 kV	N/A	$1.3 M
Western – Add a 115 kV breaker at Framingham	N/A	**Not yet provided**
Downtown - Reconfigure Kingston Substation adding four new 115 kV breaker	N/A	$14.5 M
Downtown – Add K Street tie breaker	N/A	$2.6 M
Downtown – Add 36.7 MVAR capacitor at Hartwell 115 kV	N/A	**Not yet provided**
Downtown – Add a 345 kV shunt reactor at K Street	N/A	**Not yet provided**
Downtown - Reconfigure North Cambridge 115 kV	N/A	$8.2 M
Downtown - Separate 240-510 / 110-522 DCT	4	$31.3 M
Downtown - Separate the F158 / Q169 DCT	1 Structure	$0.7 M
Downtown - Add 54 MVAR capacitor at Newton 115 kV	N/A	$1.4 M
Downtown – Add 345 kV shunt reactor at Holbrook due to minimum load analysis	N/A	**Not yet provided**
Downtown – Add 345 kV breaker at Stoughton due to minimum load analysis	N/A	$1.6 M
Downtown – Move Chelsea capacitor	N/A	$0.9 M
Transmission Owner's Cost Estimate for Common Upgrades		**$221.0 M**

One-line of Common Upgrades

APPENDIX 4-1

Analysis of Non-Transmission Alternatives ("NTA") to the Mystic to Woburn Project

(May 1, 2015)

ANALYSIS OF NON-TRANSMISSION ALTERNATIVES ("NTAS") TO THE MYSTIC TO WOBURN PROJECT: IDENTIFICATION OF FEASIBLE NTA TECHNOLOGIES AND LEVELIZED COSTS

May 1, 2015

prepared for Eversource Energy

by

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Synopsis

Eversource and National Grid (referred to collectively as the "Utilities") hired London Economics International LLC ("LEI") to conduct a Non-Transmission Alternatives ("NTA") analysis for three transmission projects, which are components of the larger transmission solution known as the "AC Solution." These transmission projects have been proposed by the Utilities in response to an identified reliability need in the Boston metropolitan area and surrounding suburbs. This report presents the technical feasibility and cost viability of implementing NTA technologies in place of one of the three transmission projects. The project, referred to in this report as the "Mystic to Woburn project" or "MWP" and it consists of a new 115-kV underground line from NSTAR's Woburn substation in Woburn, Massachusetts to NSTAR's Mystic substation in Mystic, Massachusetts.

We define technically "feasible" technologies as technologies that could be hypothetically implemented based on planning criteria and technology specific operating profiles. A technically feasible NTA technology therefore meets the reliability issues being addressed by MWP. However, a technically feasible NTA may not necessarily be cost-effective or practical. This report also addresses both the expected cost of technically feasible NTA technologies as well as the practicality of the required NTA solution.

LEI's analysis is based on simulations of the transmission system reliability needs performed by the Utilities. When studying the NTA requirements for MWP, the Utilities assumed that the other two major projects and other components of the AC Solution were constructed, in order to isolate the NTA requirements for MWP. The Utilities provided LEI with three different cases of possible NTA solutions in the form of hypothetical NTA requirements (with specific injection amounts by location). These cases relate to the maximum size of hypothetical NTA technologies considered under each case:

- Pmax set to 15 MW ("Pmax 15 MW case"): where the size of the injection amount (or requirement) associated with an NTA solution at each location was limited to 15 MW
- Pmax set to 250 MW ("Pmax 250 MW case"): where the size of the injection amount (or requirement) associated with an NTA solution at each location was limited to 250 MW, and
- Pmax set to 750 MW ("Pmax 750 MW case"): where the size of the injection amount (or requirement) associated with an NTA solution at each location was limited to 750 MW

LEI took the resulting hypothetical NTA requirements provided by the Utilities for each location and formed a list of feasible technologies by location. LEI's technology specification used a selection process that considered the size and operating characteristics of various generic NTA technologies relative to the hypothetical NTA requirement amounts and system needs under the modeled N-1 and N-1-1 contingency events.

LEI concluded that the most common technically feasible NTA technologies under the Pmax 15 MW case include peaker aeroderivatives, dual fuel jet engines, utility scale solar photovoltaic ("PV") units with energy storage and slow discharge batteries. In the larger NTA cases (Pmax 250 MW and Pmax 750 MW cases), the most common NTA technology is a combined cycle gas turbine ("CCGT"). For the smaller sized NTA case (Pmax 15 MW case), energy efficiency is also a technically feasible NTA technology from a planning perspective for a limited number of locations that have sufficient load. Distributed generation solar PV ("solar DG") and utility-scale solar PV are not technically feasible NTAs on their own, because they cannot operate during night-time hours. However, LEI has accommodated such technologies in the analysis by including the additional cost of on-site energy storage.

Using gross costs per MW of installed capacity for each technology, LEI estimated that the total costs of a technically feasible NTA solution for MWP was in the range of $144 million to $277 million a year across the three cases (Pmax 15 MW, Pmax 250 MW and Pmax 750 MW cases). However, LEI also recognized that total costs of NTA technologies can be defrayed by revenues from markets as well as other sources. Consequently, LEI computed the net direct cost to ratepayers by deducting expected average annual market-related revenues from total gross costs. Total net direct cost to ratepayers of the least cost technically feasible NTA solution for MWP was estimated to range from approximately $26 million to as much as $147 million a year. Based on practical considerations, including likelihood assessment of the revenues that could offset gross costs in the net direct cost calculus, the technically feasible NTA solution for MWP with the highest probability of occurrence would involve installing 414 MW of CCGTs and 60 MW of peaker aeroderivative units with a net direct cost to ratepayers estimated at $33 million a year (more than double MWP's estimated annual revenue requirement of approximately $10 million.)[1] This is the NTA solution associated with the Utilities' Pmax 250 MW case.

While the volume of required additions might not seem overwhelming, it remains nevertheless a challenge to develop and permit under current market conditions, mainly due to the absence of needs in the short- to mid-term as illustrated by ISO-NE's most recent forward capacity auction results (no such resources cleared the auction for the Greater Boston area). A number of other potential hurdles, including constraints on construction time (an NTA solution should be commercialization by 2018 if it were to meet the reliability needs of WWP), sufficiency of related infrastructure (such as gas pipelines), and permitting and siting challenges must also be considered.

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[1] Estimates provided by the utilities as of March 20, 2015.

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Acronyms

AC	Alternating Current
ACP	Alternative Compliance Payment
CCGT	Combined Cycle Gas Turbine
CLL	Critical Load Level
DALRP	Day Ahead Load Response Program
DG	Distributed Generation
DPU	Massachusetts Department of Public Utilities
DR	Demand Response
EFSB	Energy Facilities Siting Board
EPRI	Electric Power Research Institute
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FO&M	Fixed Operating & Maintenance
GBWG	Greater Boston Working Group
HVDC	High Voltage Direct Current
IEA	International Energy Agency
ISO	Independent System Operator
ISO-NE	Independent System Operator- New England
kW	Kilowatt
LCOE	Levelized Cost of Entry
LEI	London Economics International
MWP	Mystic - Woburn Project
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NTA	Non-Transmission Alternative
NU	Northeast Utilities (now Eversource Energy)
O&M	Operating & Maintenance
PNNL	Pacific Northwest National Laboratory
PV	Photovoltaic
REC	Renewable Energy Credit
RTO	Regional Transmission Organization
SREC	Solar Renewable Energy Credit
VOLL	Value of Lost Load
VOM	Variable Operating and Maintenance

1 Executive Summary

A Non-Transmission Alternative ("NTA") is a solution (or group of solutions) to an identified electric system need that does not involve the construction of traditional transmission infrastructure. NTA technologies may include supply-side resources (e.g. conventional generation, distributed generation or advanced generation technologies such as energy storage technologies), demand-side resources (e.g. demand response or energy efficiency), or a combination of both.

How to choose between a transmission solution and an NTA?

In theory, if an NTA can satisfactorily meet the technical requirements of the system that are driving the need for the transmission solution, it can then delay the timing of needed transmission investment. Consumers would pay for the transmission solution and may need to pay for the costs of deploying the NTA. Therefore, it is important to then compare the costs of the transmission solution against the NTA. However, it is also important to recognize that NTAs and transmission may also have different characteristics that affect other aspects of electricity service. Even if an NTA is lower cost and can fulfill the technical requirements of the system (e.g., the reliability need), there may also be other services and benefits that transmission can provide versus NTAs. Only if an NTA can fulfill all the same technical requirements and generate benefits at comparable or lower costs than those associated with transmission projects, should an NTA be pursued.

LEI was asked to determine whether there is a technically feasible combination of NTA technologies that could be more cost-effective than MWP in addressing the reliability concerns in the Greater Boston area. The Utilities prepared a set of NTA requirements that would meet the reliability needs of the system. Based on these NTA requirements, LEI identified feasible NTA technologies and their costs to evaluate the direct cost to ratepayers associated with the implementation of the least-cost, technically feasible NTA solution. A technically feasible NTA technology is defined as a technology that can meet the requirements set out by system planning criteria. System planning criteria refer to requirements such as the maximum allowable time for an NTA technology to respond to N-1 or N-1-1 contingency events (response time) and minimum duration of time for which an NTA technology must remain online after being called into service. In contrast, physical considerations, which are not a part of this methodology, refer to the amount of land and associated infrastructure required for a given NTA technology to be located at a substation. These physical considerations are assessed qualitatively in Section 5.3. It is important to bear in mind that a technically feasible NTA technology may still be impractical from a variety of other physical and financial considerations.

LEI has extensive experience working with both renewable and conventional generation technologies, as well as transmission infrastructure in the New England and Massachusetts region. LEI has also undertaken economic cost-benefit analysis, market price forecasting and asset valuation as well as presented expert witness testimony in front of various regulators in North America, including the Massachusetts Energy Facility Siting Board ("EFSB"). A detailed description of LEI's experience is presented in Appendix A.

1.1 What NTA technologies were considered?

The analysis presented in this report was designed around a mix of supply-side and demand-side technologies initially identified by both LEI and the Utilities:

1. conventional fossil fuel-fired generation (natural gas-fired peaking and combined cycle technologies);
2. large scale renewable generation (solar and wind);
3. distributed solar generation (5 MW or less in size);
4. active demand response (such as real-time demand response and real-time emergency generation);
5. passive demand response (such as energy efficiency programs); and
6. energy storage technologies (such as utility-scale battery technology and flywheels).

In undertaking the technology identification and cost analysis, LEI relied primarily on real world operating experience with such technologies in New England, as well as research documents and market information made publicly available by ISO-NE and the state of Massachusetts related to technologies' operational data and statistics. Where necessary, information from actual operational experience was supplemented with engineering–related data and generic technology information, including data on capital and operating costs, as well as operating parameters. Such generic information was collected from reputable sources, such as the US Department of Energy and affiliated national laboratories, manufacturers, and engineering procurement companies that work with such technologies. A detailed bibliography list is provided in Appendix G.

1.2 Overview of methodological approach

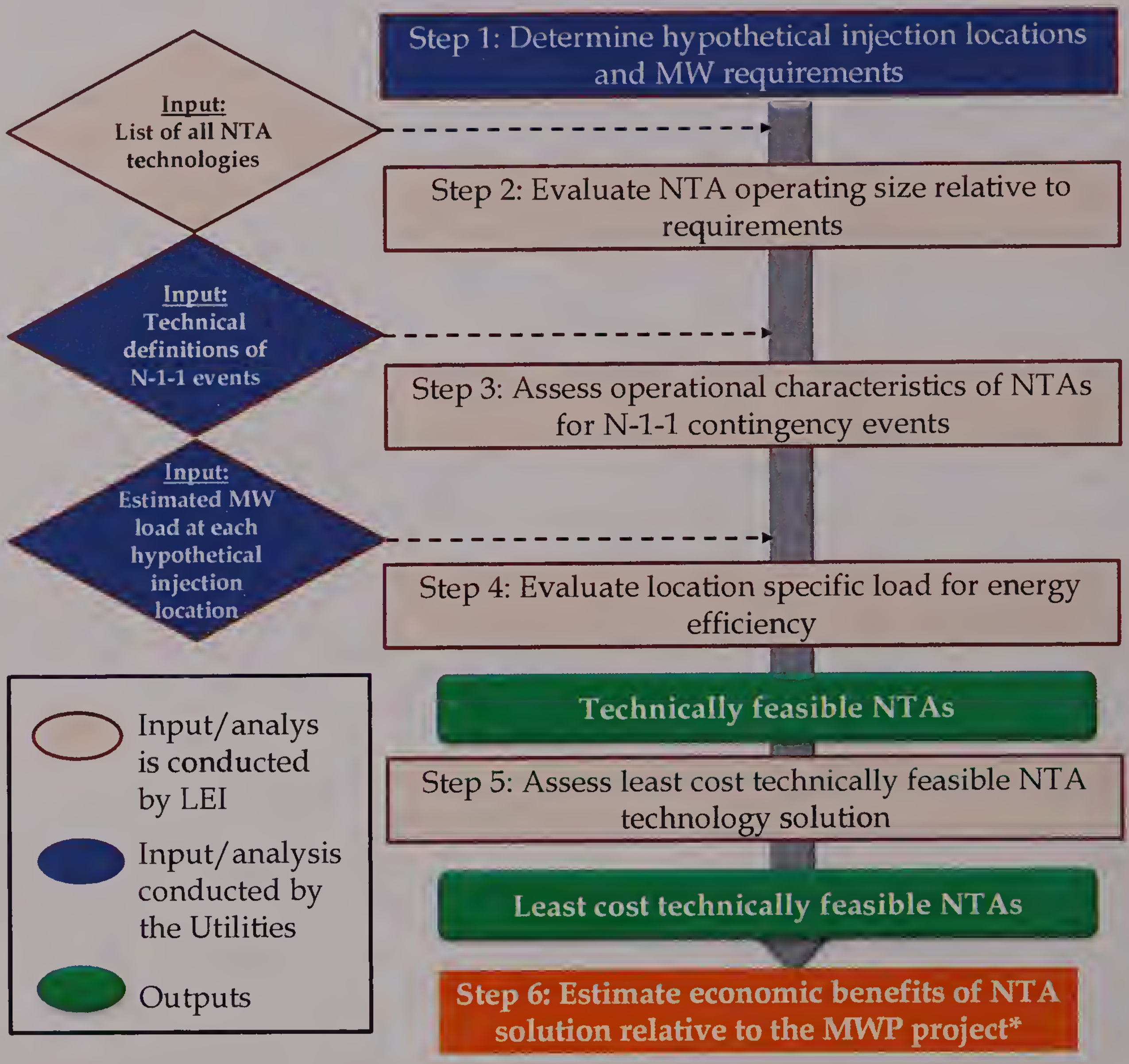
In order to identify technically feasible NTA technologies that can satisfy the reliability issues being addressed by MWP, a six-phase methodology was designed. These phases are shown in Figure 1 below and are detailed in Section 4 of this report.

The methodology starts with an assessment of hypothetical NTA solutions by the Utilities (Appendix F describes in details the assessment performed by the Utilities). Based on technical simulation analysis of the ISO-NE transmission system in and around the Boston area, the Utilities created a list of hypothetical NTA requirements in terms of MWs needed at specific locations in order to meet the same reliability requirement of the MWP (Appendix F provides a detailed overview of the methodology used to determine requirement at the injection location). The hypothetical NTA requirements for MWP were presented under three different plausible hypothetical NTA solutions:

- Small sized NTA technologies, which we refer to as the "Pmax 15 MW" case (in this case, the Utilities required a hypothetical NTA solution that is composed of individual "injections" of less than or equal to 15 MW);
- Medium sized NTA technologies, which we refer to as the "Pmax 250 MW" case (in this case, the Utilities required a hypothetical NTA solution that is composed of individual "injections" of less than or equal to 250 MW); and

- Large sized NTA technologies, which we refer to as the "Pmax 750 MW" case (in this case, the Utilities required a hypothetical NTA solution that is composed of individual "injections" of less than or equal to 750 MW).

Figure 1. Methodological Approach


Step 1: Determine hypothetical injection locations and MW requirements
Input: List of all NTA technologies
Step 2: Evaluate NTA operating size relative to requirements
Input: Technical definitions of N-1-1 events
Step 3: Assess operational characteristics of NTAs for N-1-1 contingency events
Input: Estimated MW load at each hypothetical injection location
Step 4: Evaluate location specific load for energy efficiency
Technically feasible NTAs
Step 5: Assess least cost technically feasible NTA technology solution
Least cost technically feasible NTAs
Step 6: Estimate economic benefits of NTA solution relative to the MWP project*
Input/analys is conducted by LEI
Input/analysis conducted by the Utilities
Outputs

* Beyond the scope of this report

Once the hypothetical NTA solutions were determined by the Utilities, LEI undertook a technology mapping process in order to identify and associate a technically feasible NTA technology with the hypothetical NTA requirements for each location and injection amount (i.e., capability to produce energy, measured in MW terms). LEI used decision tree techniques to sequentially filter and narrow down the available list of technologies according to the requirements at each location.

The sequence of steps in this methodology is important because it assigns a technically suitable NTA to given injection location by using a decision tree algorithm to minimize the possibility of a technical or operational mismatch. This is achieved because the first step effectively narrows down the list of injection points by dividing them into distinct sub-groups which can then be used to ensure that only technically valid NTA technologies are evaluated for injection points within that group.

While LEI recognizes that there may be multiple NTA technologies that are feasible with each injection point/amount, the purpose of this analysis is to identify technically feasible NTA technologies that possess the operating characteristics required to meet the criteria of the hypothetical NTA injections (either in terms of size, location, or operating profile). The details of LEI's methodology are presented in Section 4.3 of this report.

The next step in LEI's analysis employs a levelized cost methodology in order to evaluate the direct costs to ratepayers of implementing NTA technologies. The direct costs were calculated by aggregating the total cost of implementing least cost technically feasible NTA technologies by location. LEI first assessed the costs of technically feasible NTA solutions by evaluating the total costs of investment and operations (based on gross Levelized Cost of Entry ("LCOE") per kW year). Then, LEI considered the net costs of investment and operations that ratepayers would bear after accounting for possible market revenues and other income streams (for example, from other ratepayer-funded programs, like solar renewable energy certificates ("SRECs")).

1.3 Key Findings on technically feasible NTA technologies

While a greater number of NTA technologies like peaker aeroderivative units, utility scale solar (with storage), slow discharge batteries and dual-fuel jet engines appear as technically feasible NTA technologies under the small sized NTA case (Pmax 15 MW case), CCGTs and to a lesser extent, slow discharge batteries and peaker aeroderivative units are the predominant NTA technologies under the medium and large sized NTA cases (Pmax 250 MW and Pmax 750 MW cases). At many locations, energy efficiency resources were not technically feasible in amounts sufficient to meet the injection requirements as identified by the utilities. Certain NTA technologies do not possess operating characteristics that would be required to meet the reliability needs under N-1-1 contingency events and therefore are not technically feasible solutions.

Under the Pmax 15 MW case, slow discharge batteries, utility-scale solar PV units (with storage), dual fuel jet engines and peaker aeroderivative units qualify as feasible technologies because these types of resources can be built on a smaller scale to meet the small injection requirements at various locations. Energy efficiency also qualifies as technically feasible NTA technologies at a few select locations where NTA injection requirements are consistent with the load at that location. The underlying assumption is that at any given location, incremental energy efficiency programs could reduce peak load by up to 15%. Note that these energy efficiency programs (and accompanying peak load reductions) would need to be incremental to existing and planned programs and therefore the load reductions projected in ISO-NE's 2014 forecast for passive demand response.[2]

For medium- and large-sized NTA cases (Pmax 250 MW case and Pmax 750 MW case), CCGTs are the most frequently selected technically feasible NTA technology for MWP due to the large injection requirements under these cases. Peaker aeroderivative units and slow discharge batteries also appear as technically feasible NTA technologies at some locations under the medium and large-sized NTA cases.

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[2] ISO – NE http://www.iso-ne.com/committees/comm_wkgrps/othr/enrgy_effncy_frcst/2014frcst/iso_ne_final_2014_ee_forecast_2018_2023.pdf

Figure 2. Distribution of feasible NTAs for MWP

	Mystic-Woburn MW Injections					
	Pmax = 15		Pmax = 250		Pmax = 750	
NTA Resource	N-1 (MW)	N-1-1 (MW)	N-1 (MW)	N-1-1 (MW)	N-1 (MW)	N-1-1 (MW)
Combined Cycle Gas Turbine (CCGT)	0	0	0	393	0	393
Peaker Aeroderivative Unit	0	606	0	154	0	261
Peaker Frame Unit	0	0	0	0	0	0
Dual-fuel Jet Engine	0	454	0	6	0	15
Solar Utility Scale (with storage)	0	606	0	52	0	74
Solar Utility Scale	0	0	0	0	0	0
Solar DG with storage	0	0	0	0	0	0
Solar DG	0	0	0	0	0	0
Fast Discharge Battery	0	0	0	0	0	0
Slow Discharge Battery	0	606	0	279	0	386
Active DR - Emergency Generation	0	0	0	0	0	0
Passive DR (Energy Efficiency)	0	19	0	6	0	5
Cumulative NTA resource requirements provided by Utilities	0	606	0	445	0	552

The last row of the figure provides the total MWs required from a technically feasible NTA solution (for N-1 and N-1-1 contingency events). As can be seen, under the N-1-1 event for Pmax 15 MW case, for example, peaker aeroderivative units, utility scale solar PV (with storage) and slow discharge batteries can each meet the cumulative NTA resource needs. The final choice of which of these NTA technologies will be selected for the cost analysis at each injection location will be determined on the basis of each technology's net levelized costs.

The NTA requirements are presented under both N-1 and N-1-1 contingency events in Figure 2. Based on standard planning protocols as provided for in ISO-NE procedures and practiced by the Utilities, the N-1 and N-1-1 contingency events are defined as follows: -

- a N-1 contingency event refers to a situation when a single element of transmission or generation system fails, and a technically feasible NTA technology must be able to provide energy within five minutes and continue to operate until the failed element is repaired or as long as deemed necessary by the ISO-NE.
- a N-1-1 contingency event refers to a situation when an additional single element of transmission or generation system fails, and a technically feasible NTA technology must be able to provide energy within 30 minutes and continue to operate until the failed elements are repaired or as long as deemed necessary by the ISO-NE. Typically, ISO-NE can resolve contingency events within a 12 to 24 hour cycle, and LEI has conservatively assumed a 12 hours duration to resolve the contingency in its analysis.

It is important to note that MWP does not require a solution under N-1 NTA contingency events. This implies that in a contingency event where a single generation or transmission element undergoes failure, the system as a whole is robust enough to prevent any instability without MWP (this is assuming that the entire Greater Boston solution is implemented with the exception of the Mystic to Woburn line). However, under N-1-1 contingency events, NTA solutions are required in lieu of MWP. This indicates that the technically feasible NTA technologies must be able to inject power within 30 minutes of a second contingency event, and should able to maintain that level of operations continuously for 12 hours.

In addition, the Utilities have provided an estimate of the Critical Load Level ("CLL"). CLL is defined as the load level at which a system problem could occur, and therefore a solution would be needed.[3] LEI uses the CLL to compare the hourly forecasted load profile of the Greater Boston zone to identify when a NTA technology would be required to operate to prevent reliability problems should a contingency event occur during those periods.[4]

Given the hypothetical NTA requirements, some technologies are not technically viable, mainly due to their operational characteristics. For example, fast discharge energy storage resources (such as flywheels and other fast discharge batteries) are not technically feasible on a standalone basis because they cannot inject power continuously for 12 hours as required by an N-1 or N-1-1 contingency event.

Other small scale NTA technologies, such as solar DG, cannot effectively meet the technical requirements of the contingencies and the sizing required of hypothetical NTA requirements at the various locations. Solar DG resources have an operating profile that does not provide for the sustained performance required under N-1 and N-1-1 contingencies. Even if solar DG were to be paired with energy storage technologies (such as batteries) to overcome the intermittency of operation, LEI's methodology was not able to qualify solar DG units as technically feasible NTA technology because of the very small amount of the power that a typical 5 MW solar DG unit can produce. Specifically, in Massachusetts, a solar DG unit is conventionally defined as less than 5 MW of nameplate capacity and exhibits an average performance rate of 15%, implying that a 5 MW unit would only produce 0.75 MW of energy on average. There were no locations with an NTA requirement of such a small size in each of the three cases prepared by the Utilities.

Of course, it is possible to add more than one stand-alone solar DG project at a given location (substation). However, there is some uncertainty as to the maximum number of feeder connections that could be allowed at any given substation.[5] Moreover, considering that utility scale solar PV resources (with energy storage) have the same performance profile as solar DG resources (with energy storage), the selection of utility scale solar PV resources can also proxy for a situation where several solar DG installations *could* serve as a technically feasible NTA (although such a combination of multiple solar DG installations would operate at a higher cost than the utility scale (notably, the gross LCOE can be as much as 40% lower for utility-scale solar PV as compared to solar DG)). In effect, a larger sized utility scale solar PV project mimics the presence of several smaller solar DG units at the same location.

Finally, it bears noting that Real-Time Active DR ("RTDR"), which is typically associated with industrial or large commercial customer sites (such as manufacturing facilities or processing factories), were not directly taken into consideration in the analysis, although LEI still considered them as potential NTA technologies. There is a lack of publicly available information on RTDR's operational mode (such parameters will vary with equipment and size), timing and duration of operation, as well as response/ performance rates and opportunity costs, which does not allow us to model these technologies with confidence. Furthermore, under ISO-NE's rules, RTDR and real-time emergency generation ("RTEG") are not typically operable at any given time of the day, which would be a stumbling block to their technical feasibility under N-1-1 contingency events.[6] For reference purposes, LEI nevertheless estimated gross and net LCOE figures associated with both RTDR and RTEG in Appendix C.

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[3] Section 5.5: Information on Critical Load Level. Regional System Plan 2013. Available at: http://iso-ne.com/static-assets/documents/trans/rsp/2013/rsp13_final.docx.

[4] See Appendix B for the forecasted hourly load in the Greater Boston zone, as provided to LEI by the Utilities.

[5] A comprehensive system impact study was beyond the scope of the current work plan, and would have been necessary, according to the Utilities' experts, to establish the precise number of feeders that could be viable at every location.

Technically, peaker frame units can also operate in the size range of between 20 and 250 MW, but these units do not qualify as a technically feasible NTA technology due to technical and market economics-related reasons. Under N-1 and N-1-1 contingency events, a technically feasible NTA technology would be required to be able inject power within 5 minutes and 30 minutes, respectively. In order for peaker frame units to fulfill these timing requirements, and given the source of fuel (i.e., pipeline gas) and nominations required for such fuel, such units would need to be effectively committed day-ahead in order to be capable of operating in real-time, as they would not be able to ramp up from a cold start given the advance notice required for fuel supply and also the speed of ramping. Although the ISO-NE has the authority to commit resources "out-of-merit" day ahead, bringing online a gas-fired frame peaker and having it running essentially "out-of-merit" in order to be prepared for contingencies may be expensive and potentially distort market price signals. The ISO-NE may have more economic resources available for such purposes, such as other types of peakers (including dual fuel aeroderivative units and jet engines) for such contingencies. Due to these operational considerations, LEI did not qualify peaker frame units as technically feasible NTA technologies for N-1 and/or N-1-1 contingency events.

Nameplate capacity (MW) of technically feasible NTA technologies depends on the NTA injection requirement as well as technology specific characteristics

The minimum and maximum operating sizes for the NTA technologies under consideration are based on the typical operating size ranges of such technologies in New England. While certain NTA technologies might appear to be technically feasible based on their typical operating size, these technologies may not qualify, once adjustments are made for their performance profile. For instance, let us take an NTA requirement of 5 MW at a given location. A solar resource's nameplate capacity would need to be as much as 33.4 MW in order to reliably provide 5 MW of energy throughout the year. In other words, it would need to be "up-sized" to account for the quality of solar resources (as measured by an annual average capacity factor) in New England, which is approximately 15% average performance rate. In this case, solar DG units, which by regulatory definitions have a size capped at 5 MW, will then become infeasible (if we are to require that one unit per technology meet the requirement in each location). In general, technically feasible NTA candidates with low performance ratios would need to be significantly larger in nameplate capacity terms than the resource requirements at given injection points in order to qualify, as shown in the chart below. Figure 3 presents, for each case, a comparison of the NTA requirements provided by the Utilities (gray column on the left), against the sum of injection amounts from technically feasible NTA technologies (middle column) and the effective nameplate installed capacity required to supply those injection amounts using the specific technically feasible NTA technologies for each case (right column). All numbers in Figure 3 are in MW, although the scales for each case are different.

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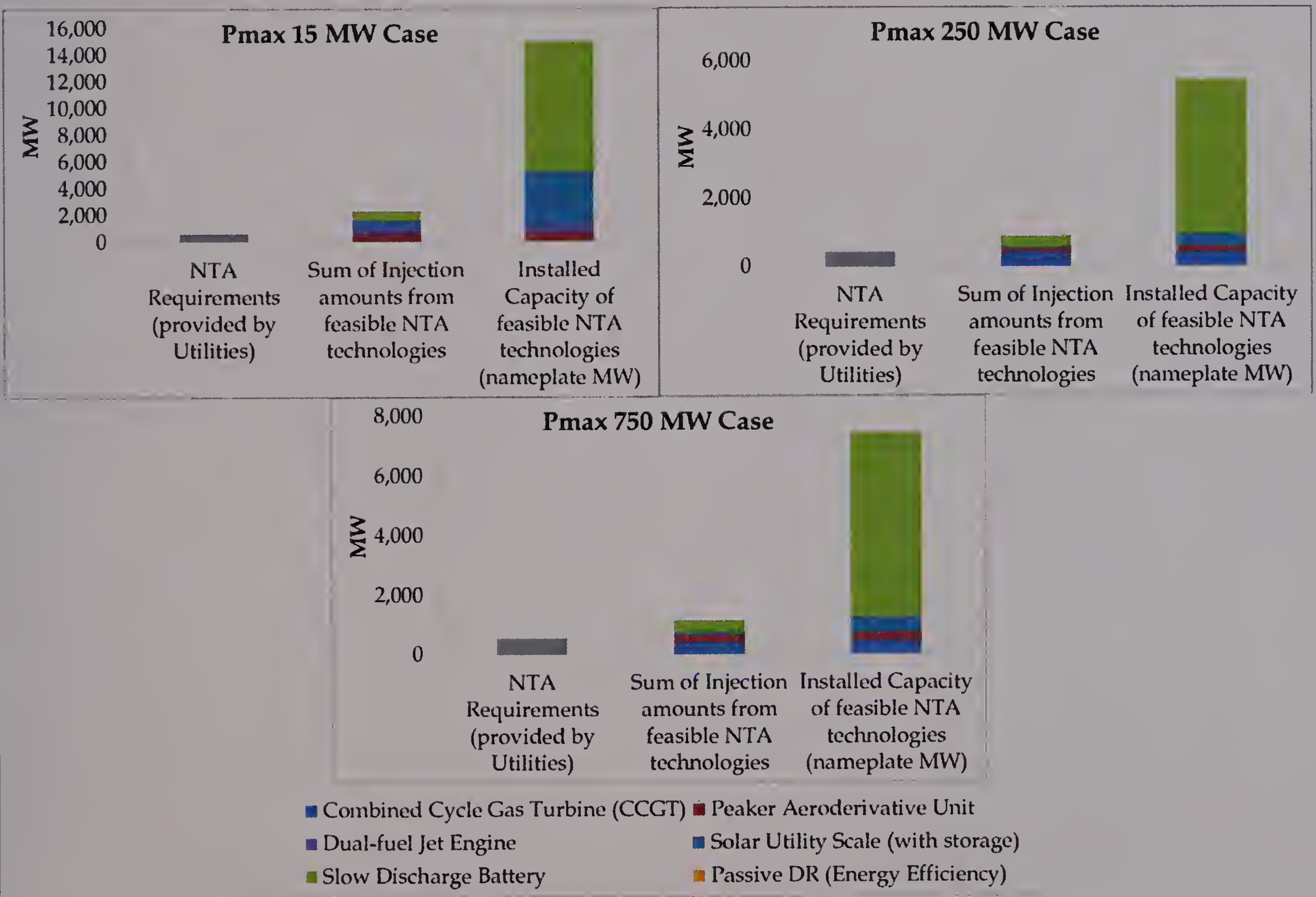
[6] " ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand

Resources, Asset Related Demands and Alternative Technology Regulation Resources." *ISO-NE, November 7, 2014* http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

Figure 3. Comparison of NTA requirements against sum of injection amounts from technically feasible NTAs, and equivalent installed capacity required to provide injection amounts (*scale varies by case*)



Note: It is important to note that the installed capacity under Pmax 15 MW case is substantially higher than under the other two cases because a larger amount of NTA requirements estimated by the Utilities, and also due to the predominance of slow discharge batteries as technically feasible NTA technologies under this case. A significant number of injection requirements under the Pmax 15 MW case are 15 MW, which can be provided by slow discharge batteries. However, in order for these batteries to supply 15 MW for the 12 consecutive hours as required by a contingency event, the equivalent effective installed capacity (nameplate MW) has to be more than 180 MW (15 MW *times* 12 hours and adjusted for the efficiency factor associated with the charging and discharging cycle). We assume that it is technically possible to connect a number of battery units to achieve an effective installed capacity large enough to continuously supply 15 MW of energy per hour for 12 hours. Further in the analysis, large installations of batteries get eliminated on account of their higher cost relative to other technologies of similar size

As illustrated in Figure 3, under each case, the NTA requirements provided by the Utilities (left-hand, gray column) are smaller than the sum of injection amounts from technically feasible NTA technologies (middle column). Also, the sum of injections from technically feasible NTA technologies (middle column) is smaller than the installed capacity of technically feasible NTA technologies (right-hand column). This happens because, for example, under the Pmax 15 MW case, the sum of injection amounts from technically feasible NTA technologies (2,292 MW) is larger than the NTA requirements provided by the Utilities (606 MW) because 2,292 MW represents the sum of all technically feasible NTAs that can meet the requirements. In other words, more than one technically feasible NTA technology exists that can meet the requirements of the hypothetical NTA solution. Similarly, the installed capacity of technically feasible NTA technologies (15,011 MW) is greater than the sum of injection amounts from technically feasible NTA technologies (2,292 MW) because each of the technically feasible NTA technologies is scaled up using its performance rates (for example, the annual average capacity factor for solar technologies, the efficiency of the battery charging and discharging cycle, and the forced outage rate for thermal generation) in order to produce the requisite amount of energy injections for the NTA requirement.[7] This scaling up to get to the notional installed capacity (nameplate rating) also forms the basis for the levelized cost analysis.

1.4 Key Findings from cost analysis

The cost analysis was performed across all considered cases (Pmax 15 MW, Pmax 250 MW and Pmax 750 MW cases). LEI developed estimates of gross LCOE and Net LCOE for each technically feasible NTA technology. The gross LCOE is an annual per kilowatt of installed capacity figure ($/kW-year) that embodies all investment and operating costs, including capital costs (equity and debt), fixed operating and maintenance ("FOM") costs, fuel costs (where relevant), and variable operating and maintenance ("VOM") costs. Net LCOE for each NTA technology is derived by deducting from gross LCOE a bundle of potential revenues and income streams associated with each NTA technology. The net LCOE is used to reflect the fact that total direct cost to ratepayers could be reduced through revenues earned from the wholesale energy and capacity markets or other income streams.[8]

For each injection point, under a given case, LEI calculated the total costs for all identified technically feasible NTA technologies based on the combination of their respective gross LCOE (or net LCOE) and total capacity needs (at the injection location), with adjustment for operating factors.[9] There are many permutations of NTA solutions, given that multiple NTA technologies may qualify at each location. LEI selected the least costly combination by comparing the resulting costs across all technically feasible NTA technologies at each location and selecting the least costly technically feasible NTA technology. Finally, we aggregated costs of all identified least cost technically feasible NTA technologies across all injection locations to derive the overall direct cost for ratepayers per case.

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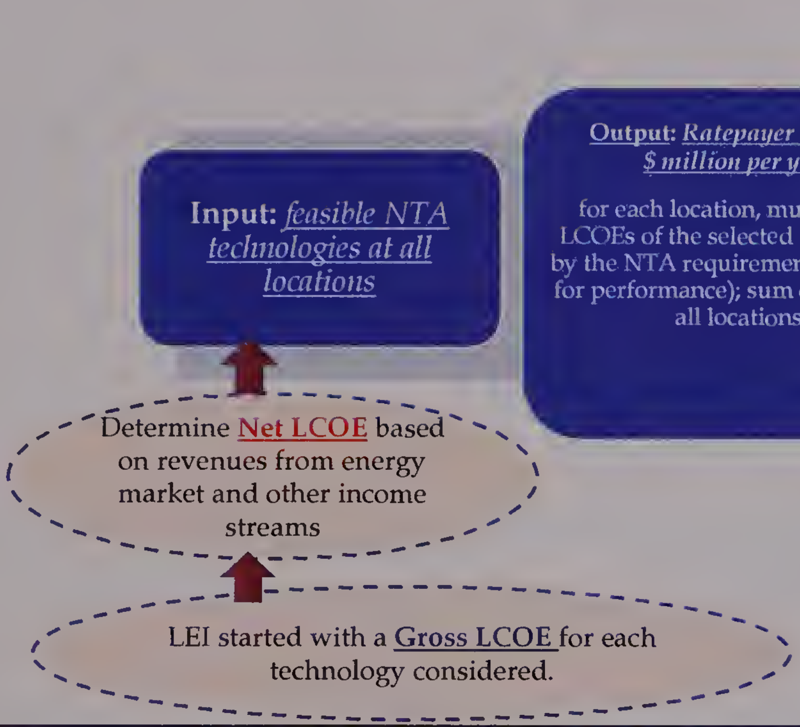
[7] Please see Appendix B for more details.

[8] These revenues were estimated notionally based on current market intelligence and are discussed further in Section 5.2.2.

[9] Operating factors include capacity factor, availability factor (which is defined as 1-forced outage rate), and ramping rates, which describe how "fast" a power plant can increase or decrease output - it is usually defined in MW per minute.

Figure 4. Methodology for estimating net direct costs of technically feasible NTA technologies ($/kW-year)


Input: feasible NTA technologies at all locations
Output: Ratepayer Costs in $ million per year
for each location, multiply the LCOEs of the selected technology by the NTA requirement, (adjusted for performance); sum costs across all locations
Select the least cost NTA technology (or combination of technologies) at each location
Determine Net LCOE based on revenues from energy market and other income streams
LEI started with a Gross LCOE for each technology considered.

The cost analysis begins with the evaluation of total cost of technically feasible technologies based on gross LCOE and installed capacity (nameplate rating). Under the baseline gross LCOE, annual gross costs for a technically feasible NTA solution for MWP were estimated to range between $181 million and $231 million across the three cases (Pmax 15 MW, Pmax 250 MW and Pmax 750 MW case). When adding a +/- 20% sensitivity on gross LCOEs, the resulting gross costs range from $145 million to $277 million a year across the three cases (Pmax 15 MW, Pmax 250 MW and Pmax 750 MW case).

LEI recognizes that total costs of NTA technologies can be defrayed by revenues from markets as well as other sources. In order to capture an accurate estimate of net direct cost to ratepayers from technically feasible NTA solutions, LEI deducted these revenues from the gross costs (to derive net LCOE). Nonetheless, there is a lot of uncertainty on the magnitude and sustainability of these revenue offsets. To account for that uncertainty, LEI also conducted a scenario analysis on the net LCOEs.

LEI ran four scenarios for each case (Pmax 15 MW, Pmax 250 MW, and Pmax 750 MW cases) that considered a range of possible net LCOEs. The scenario analysis demonstrated the impact of key market assumptions, such as the magnitude of SRECs and implications of NTA resources clearing (or not clearing) the Forward Capacity Market ("FCM") on ratepayers' net direct costs. There is a big difference between current levels of SREC ($245/MWh for 2017 forwards) and the levels that such products could trade at by 2020 upon expiration of the Solar Carve-out program II.[10] Moreover, over time as additional solar capacity comes online, that may also depress the SREC price. For some NTA technologies, SRECs revenue assumptions can critically impact the estimate of direct net costs.

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[10] The Solar Carve-out program II was launched in 2014 by the Massachusetts Governor with the target to install of 1.6 GW by 2020.

Therefore, LEI considered two levels of future SREC prices in the analysis. The impact of SREC revenues on ratepayers' net costs could vary a great deal based on market conditions and price levels - we captured this fact in the scenarios described in the following table.

In the most recent ISO-NE forward capacity auction ("FCA") (planning year 2018/2019), no CCGT generating unit cleared the auction in the Greater Boston area; we do not anticipate such needs for the next few auctions. In addition, given that ISO-NE's Interconnection Queue features less than 750 MW of proposed CCGT generation for the Boston area, it is unlikely that the considered NTA technologies would receive forward capacity market payments in all years. Therefore, we assumed half of capacity revenues in Scenarios 1 and 4 and tested the impact of the lack of capacity payments in scenarios 2 and 3. Figure 5 provides a summary of the four scenarios.

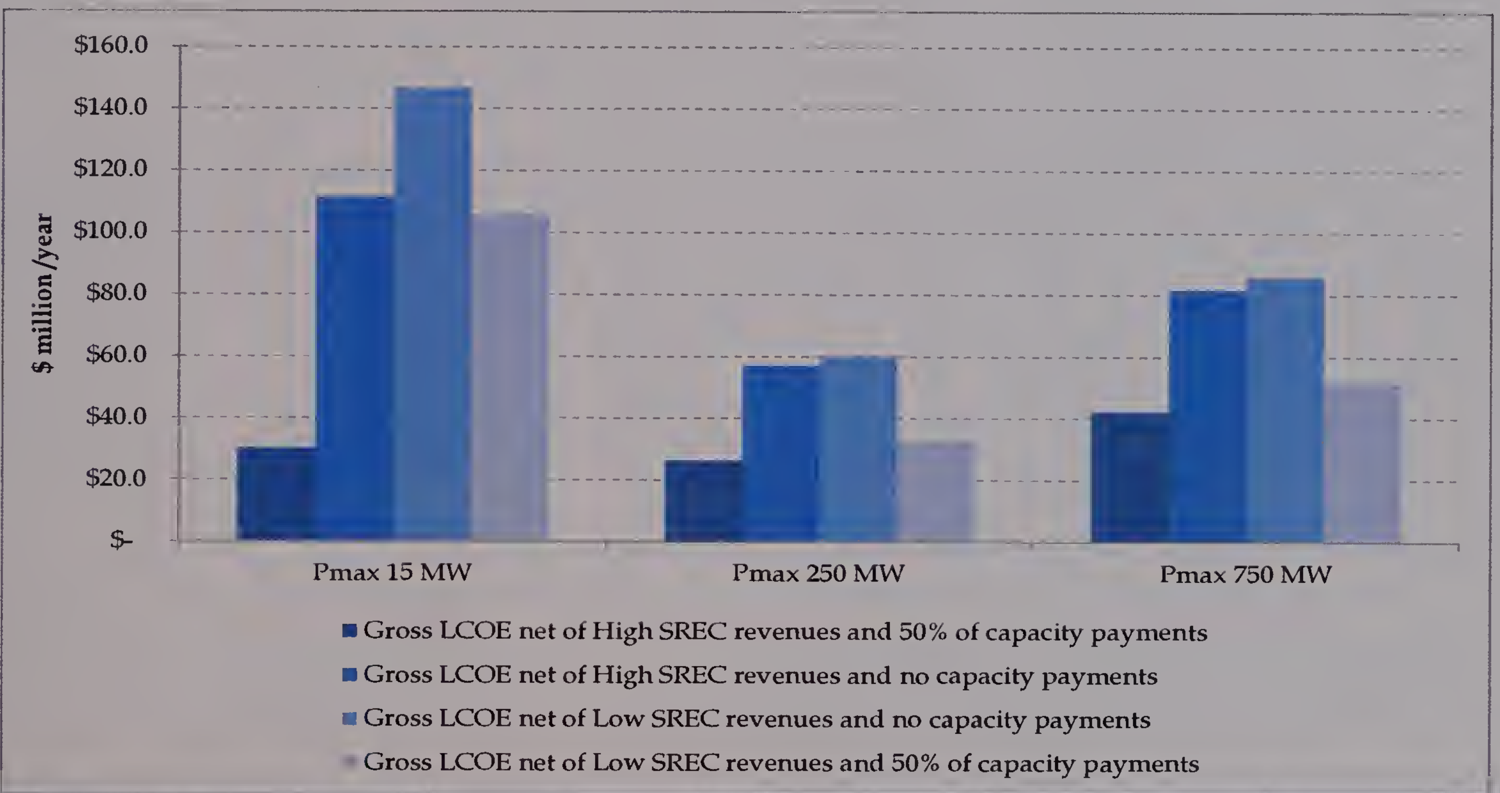
Figure 5. Summary of LEI's scenarios

Scenarios	Methodology	Key assumptions for net LCOE
Scenario 1 *(Gross LCOE net of High SRECs revenues and half FCM payments)*	**Net LCOE used to select the least cost technologies**	▪ We assume that by 2018-2020 solar resources will earn REC revenues at prices similar to 2017 SREC forwards ($321/kW-month) ▪ We assume that new resources such as CCGT and peakers would receive capacity payments for about half of their life cycle given the absence of need for such resources in the short to mid-term
Scenario 2 *(Gross LCOE net of high SRECs and no FCM payments)*	**Net LCOE used to select the least cost technologies**	▪ Same assumptions on SREC prices as Scenario 1 ▪ We assume no FCM revenues (no resources clear in the FCA)
Scenario 3 *(Gross LCOE net of Low SRECs revenues and no FCM payments)*	**Net LCOE used to select the least cost technologies**	▪ We assume that by 2018-2020 solar resources will earn REC revenues at prices similar to MA Class I REC ACP ($88/kW-month) ▪ We assume no FCM revenues (no resources clear in the FCA)
Scenario 4 *(Gross LCOE net of Low SRECs revenues and half FCM payments)*	**Net LCOE used to select the least cost technologies**	▪ We assume that by 2018-2020 solar resources will earn REC revenues at prices similar to MA Class I REC ACP ($88/kW-month) ▪ Same assumptions on FCM payments as Scenario 1

The range of net direct costs to ratepayers was estimated at $26 million to $147 million per year over the various scenarios and the three cases. However, some scenarios and NTA solutions (cases) are very unlikely from a practical perspective and given reasonable, longer term outlook for the relevant markets. Based on methodic consideration of the likely market revenues achievable over the life of an asset and the practicality of bringing the considered assets to commercial operation under each scenario and case, scenario 4 (where we are modeling low SREC revenues and capacity payments for 50% of the economic life of the technically feasible NTA technologies) is the most probable (see Section 5.2.2 for more details). The case that produces the lowest net direct cost to ratepayers under scenario 4 (and which proves to be the most practical from a development perspective) is the Pmax 250 MW case, where the technically feasible NTA technologies are primarily CCGTs. Under this scenario and case, the net direct cost to ratepayers is estimated at $33 million a year (more than double the estimated approximately $10 million annual revenue requirement of MWP). The commercial realization of the selected scenario still contains challenges. The Pmax 250 MW case under scenario 4 requires 414 MW of

CCGTs and 62 MW of peaker aeroderivative units spread over 8 sites by 2018. Siting, permitting, and then constructing such an amount of new gas-fired generation over that many sites within the next three years would be challenging given siting requirements, market rules and associated timelines, and current system conditions in the Greater Boston area. There will be practical hurdles with identifying construction teams, acquiring land, procuring the equipment, and building out the requisite fuel supply infrastructure (as well as negotiating the fuel supply contracts). Furthermore, the ISO-NE wholesale power market has not established a market "need" for new gas-fired resources in the Greater Boston sub-region. All-in-all, even though the NTA solution under the Pmax 250 MW case is technically feasible and least cost (of all the NTA solutions), it would still very impractical and commercially challenging, which reduces the probability of successful implementation of such an NTA solution to meet the reliability needs of the Greater Boston sub-region.

Figure 6. Estimated net direct costs of NTA solution for MWP per annum based on varying assumptions regarding net LCOEs



No Mystic - Woburn	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Scenarios	Gross LCOE net of High SREC revenues and 50% of capacity payments	Gross LCOE net of High SREC revenues and no capacity payments	Gross LCOE net of Low SREC revenues and no capacity payments	Gross LCOE net of Low SREC revenues and 50% of capacity payments
Pmax15 MW				
Total cost ($ million/ year)	$30.2	$111.3	$146.7	$105.8
Pmax 250 MW				
Total cost ($ million/year)	$26.3	$57.0	$60.0	$32.8
Pmax 750 MW				
Total cost ($ million/year)	$42.2	$81.6	$85.9	$51.5

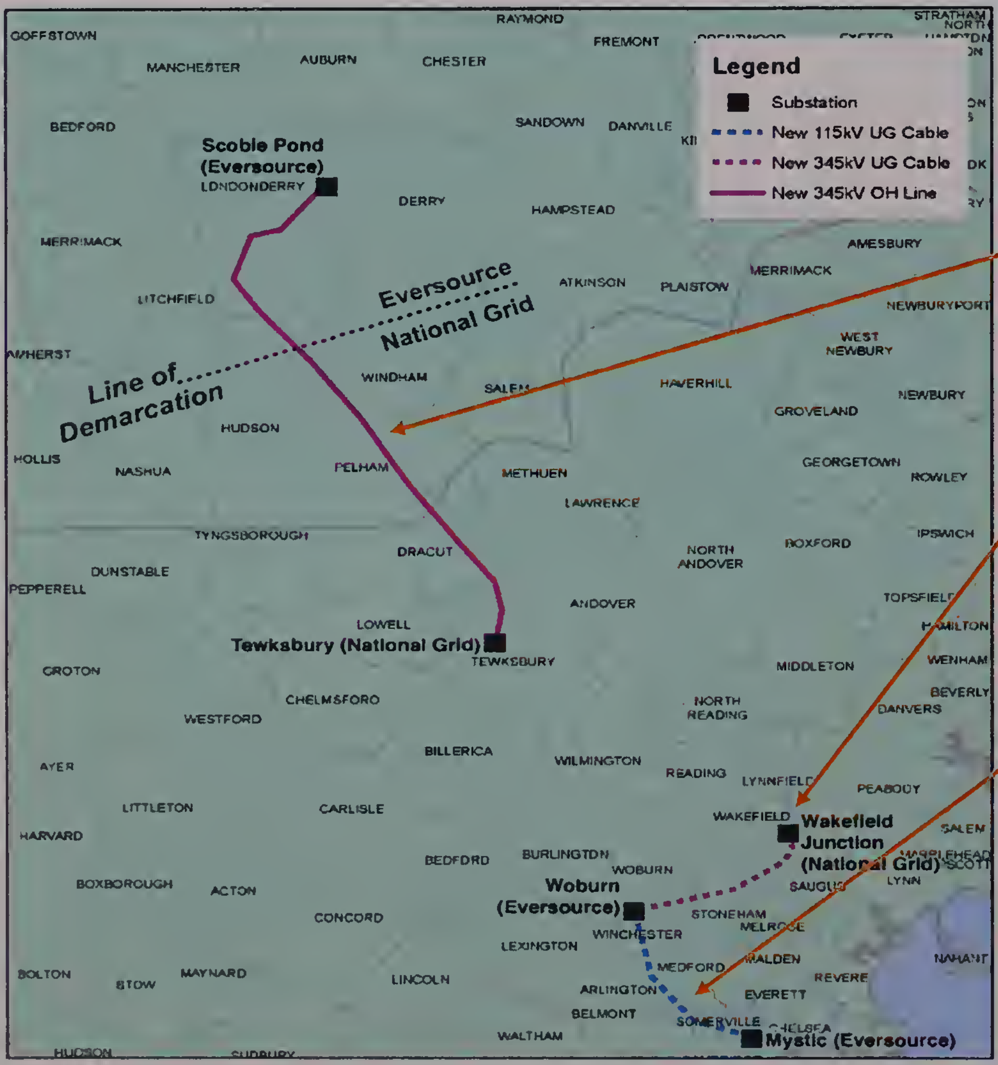
2 Background on the MWP and Greater Boston AC Solution

2.1 Greater Boston AC Transmission Reinforcement Projects

The Greater Boston Study is a large area transmission planning study led by ISO-NE and conducted by the Greater Boston Working Group ("GBWG"). The study includes an evaluation of the reliability performance of the transmission system serving the Greater Boston area for the 2018 and 2023 projected system conditions. The GBWG issued the "Needs Assessment[11]" and identified certain areas of the system where transmission system performance fails to meet North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), and/or ISO-NE standards and criteria.

In order to address the issue, the GBWG has developed a transmission solution that includes (among other components) three unique transmission line elements as illustrated in the map below. The solution was selected by ISO-NE as the preferred option to address reliability issues in the Greater Boston area on February 12, 2015.

Figure 7. Mapping of the three unique transmission projects of the AC solution


Legend
■ Substation
New 115kV UG Cable
New 345kV UG Cable
New 345kV OH Line
Scoble Pond (Eversource)
Tewksbury (National Grid)
Wakefield Junction (National Grid)
Woburn (Eversource)
Mystic (Eversource)
Eversource
National Grid
Line of Demarcation
GOFFSTOWN
MANCHESTER
AUBURN
CHESTER
RAYMOND
FREMONT
BEDFORD
LONDONDERRY
DERRY
SANDOWN
DANVILLE
HAMPSTEAD
MERRIMACK
LITCHFIELD
ATKINSON
PLAISTOW
AMESBURY
NEWBURYPORT
WEST NEWBURY
NEWBURY
WINDHAM
SALEM
HAVERHILL
GROVELAND
HUDSON
HOLLIS
NASHUA
PELHAM
METHUEN
LAWRENCE
GEORGETOWN
ROWLEY
TYNGSBOROUGH
DRACUT
NORTH ANDOVER
BOXFORD
IPSWICH
DUNSTABLE
PEPPERELL
ANDOVER
TOPSFIELD
HAMILTON
WENHAM
LOWELL
TEWKSBURY
GROTON
MIDDLETON
BEVERLY
CHELMSFORD
WESTFORD
NORTH READING
DANVERS
AYER
BILLERICA
WILMINGTON
READING
LYNNFIELD
PEABODY
LITTLETON
CARLISLE
WAKEFIELD
SALEM
HARVARD
BEDFORD
BURLINGTON
WOBURN
SAUGUS
LYNN
BOXBOROUGH
ACTON
STONEHAM
MELROSE
CONCORD
WINCHESTER
LEXINGTON
MEDFORD
MALDEN
NAHANT
BOLTON
STOW
MAYNARD
LINCOLN
ARLINGTON
REVERE
EVERETT
BELMONT
SOMERVILLE
CHELSEA
WALTHAM
HUDSON
SUDBURY

The three unique transmission components

A. New overhead 345-kV line in existing rights-of-way in Londonderry, Windham, Hudson, and Pelham, NH, and Dracut, Andover, and Tewksbury, MA
B. New underground 345-kV line through Woburn, Winchester, Stoneham, and Wakefield, MA.
C. A new underground 115-kV line through Everett, Boston (Charlestown), Somerville, Medford, Winchester, and Woburn, MA

Source: National Grid and Eversource Energy

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[11] Final Needs Assessment presented to Planning Advisory Committee on January 30, 2015.

These three transmission projects will be the subject of petitions to the Massachusetts Department of Public Utilities ("DPU") and/or EFSB, as well as other federal, state and local authorities. National Grid and Eversource Energy ("the Utilities") performed detailed transmission system analysis to quantify the total amount of injection or withdrawals that may eliminate each of the reliability-driven needs for new transmission. These injections or withdrawals are the initial hypothetical quantities of NTA needs.

2.2 The Mystic - Woburn Project

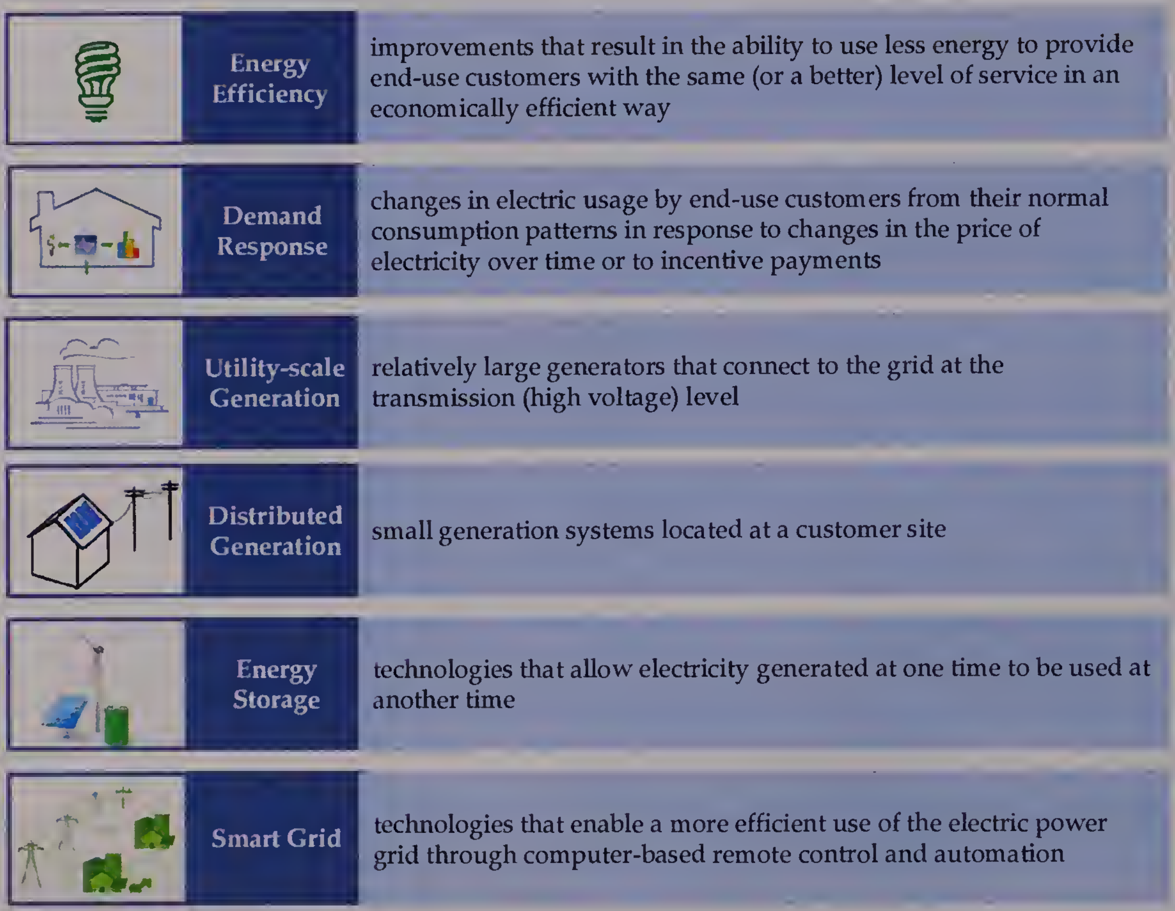
MWP is one of the three unique transmission projects that are components of the Greater Boston AC Solution. This is a joint project between Eversource Energy (formerly Northeast Utilities) and National Grid. The MWP consists of a new 115-kV 7 miles underground line from NSTAR's Woburn substation in Woburn, Massachusetts to NSTAR's Mystic substation in Mystic, Massachusetts.

3 What is an NTA?

An NTA is a solution (or a group of solutions) to an identified electric system need that does not involve the construction of traditional transmission infrastructure. NTAs may include supply-side resources (e.g. conventional generation, distributed generation and advanced generation-like technologies such as batteries and storage), demand-side resources (e.g. demand response and energy efficiency), or a combination of the two. More recently, the term "NTAs" has been expanded to include smart grid distribution technologies.

Discussions of NTAs occurring in wholesale power markets and at state regulatory bodies generally focus on six categories of NTA technologies as described further in Figure 8 below: energy efficiency; demand response; utility-scale generation; distributed generation; energy storage; and smart grid technology.

Figure 8. NTA Technology Categories



Energy Efficiency	improvements that result in the ability to use less energy to provide end-use customers with the same (or a better) level of service in an economically efficient way
Demand Response	changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments
Utility-scale Generation	relatively large generators that connect to the grid at the transmission (high voltage) level
Distributed Generation	small generation systems located at a customer site
Energy Storage	technologies that allow electricity generated at one time to be used at another time
Smart Grid	technologies that enable a more efficient use of the electric power grid through computer-based remote control and automation

Note: LEI was not asked to consider SmartGrid as a technology category in the analysis of MWP because it is relatively untested and there is limited data available to model it as an NTA technology with confidence.

Consistent with the general categories of NTA technologies and adjusted for what is reasonable in New England (and specifically in eastern Massachusetts), the analysis presented in this report was designed around a list of six types of NTA technologies initially identified by both LEI and the Utilities:

1. conventional fossil fuel fired generation (natural gas-fired peaking and combined cycle technologies);
2. large scale renewable generation (solar and wind);

3. distributed solar generation (5 MW or less in size);
4. active demand response (such as real-time demand response and real-time emergency generation);
5. passive demand response (such as energy efficiency programs); and
6. energy storage technologies (such as utility-scale battery technology and flywheels).

The six types of NTA technologies listed above include both supply-side and demand-side resources. Supply-side technologies include conventional fossil fuel-fired generation, large-scale renewable generation, and energy storage technologies. Demand-side technologies include distributed generation and various forms of demand response. Demand-side technologies can also include applications with energy storage technologies.

Each of these NTA technologies has inherent operating characteristics that may determine their applicability as a technically feasible NTA technology vis-à-vis the reliability-driven requirements for a solution. When evaluating the practical feasibility of NTA technologies (ability for the NTA technologies-based solution to be implemented in real life) versus a transmission line, the analysis must be done in a way that would make NTAs and transmission comparable in terms of both technical characteristics (reliability) and economic attributes (costs and benefits), as we discuss further below.

3.1 Evaluation of an NTA

As part of its ongoing work with the energy industry, LEI has proposed a set of tools and analytical techniques to allow for a comprehensive evaluation of NTAs and transmission solutions.[12] Although the specific steps and analytical tools can differ, subject to the specific context of a given investment need and system operator's planning process, there are a number of guiding principles that must be considered. First and foremost, a rigorous analysis should acknowledge that NTA technologies and transmission will provide different services and therefore could generate different levels of benefits for consumers. Furthermore, a rigorous analysis needs to ensure that NTAs meet the technical needs underpinning the transmission solution. Finally, LEI recommends that a comparative analysis is conducted within the discipline of cost-benefit framework, where benefits and costs are considered as comprehensively as possible. Economic cost-benefit analysis should consider the dynamic evolution of the system, rational market response to NTAs and/or transmission, and consideration of the operational uncertainties of each over time.

LEI has applied these principles in this NTA analysis. The study begins with the simulation-based analysis performed by the Utilities, where the reliability requirements of the system are presented in the form of location-specific NTA requirements under three plausible solutions. LEI then assigned technologies to the specified NTA requirements using a logical decision tree process to sequentially filter and narrow down the available list of technologies that meet the technical needs underpinning the solutions. Next, LEI employed a levelized cost methodology in order to evaluate the direct costs to ratepayers of implementing NTA technologies. LEI's cost analysis was designed to be as comprehensive as possible. For each NTA technology LEI developed an all-in cost (gross LCOE) inclusive of development and operation costs (capital cost, fixed and variable operating and maintenance cost, and fuel cost). The net LCOE were then derived by adjusting gross LCOE from potential revenues yielded by the NTA technologies.

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[12] *Market Resource Alternatives – an examination of new technologies in the Electric Transmission Planning Progress*, WIRES Group, September 2014.

Another stage of LEI's analysis involves comparing the benefits originating from a solution consisting of technically feasible NTA technologies versus those of WWP. At this time, such analysis has been determined to be outside the scope of this report.

3.2 Prospective NTA technologies

Twelve selected prospective NTA technologies have been short-listed based on their ability to operate in the Greater Boston Region. The considered technologies have unique operating characteristics which are compared against NTA injection requirements to determine their feasibility. Figure 9 lists the technologies under consideration for technically feasible NTA technologies. In addition, the figure also outlines typical capacity ranges, operating profiles and performance rates associated with these technologies, which are detailed in Appendix B. In addition to stand-alone NTAs, the analysis also includes various practical combinations such as solar PV with storage, which are also included in the figure below.

In undertaking the technology identification and cost analysis, and for developing the technical assumptions in Figure 9, LEI relied primarily on real world operating experience with such technologies in New England, as well as research documents and market information made publicly available by ISO-NE and the state of Massachusetts related to technologies' operational data and statistics. Where necessary, actual operational information was supplemented with engineering–related data and generic information on technologies, including generic information on levelized costs. Such generic information was collected from reputable sources, such as the US Department of Energy and affiliated national laboratories, manufacturers, and engineering procurement companies that work with such technologies. A detailed bibliography list is provided in Appendix H.

As can be seen in Figure 9, the performance rate for solar technologies is assumed to be at 15% on average over the year. While this may seem low relative to the performance rates of thermal technologies, it is in line with actual performance of solar units in Massachusetts.[13]

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[13] We assumed an annual average capacity factor of 15% for solar PV in Massachusetts based on modeling results as documented in NREL's System Advisor Model. An annual average capacity factor of 15% is consistent with the state of Massachusetts' estimated solar PV's capacity factor of 13% (see "SREC project calculation", Massachusetts Energy and Environmental Affairs – Department of Energy Resources). It is worth noting that the annual average capacity factor that is required for assessment of performance in LEI's analysis is distinct from 35% derating factor that ISO-NE is currently assuming for its analysis of solar DG. The 35% derating factor is used to determine a capacity contribution from such resources in ISO-NE's planning documents and therefore it represents the potential performance only during the summer super-peak hour rather than the average performance across all hours that is measured by an annual capacity factor (see 2014 Interim Forecast of Solar Photovoltaic (PV) Resources, ISO-NE). For assessing the technical feasibility of a technology to meet the NTA requirements, LEI employs the annual capacity factor as contingency events can occur anytime – not just during the summer super-peak. In the net direct costs analysis, LEI uses both the annual capacity factor and the 35% derating factor.

Figure 9. Descriptive summary of NTA technologies

NTA Resource	Installed Capacity range	Operations profile	Performance Rate
Combined Cycle Gas Turbine (CCGT)	100 to 800 MW range in MA	Baseload	95% availability factor
Peaker Aeroderivative Unit	1 to 125 MW range in MA	Peaking load	85% availability factor
Peaker Frame Unit	20 to 250 MW range in MA	Peaking load	83% availability factor
Dual-fuel Jet Engine	<1 to 50 MW	Peaking load	85% availability factor
Solar Utility Scale (with storage)	5 to 250 MW	Potential baseload depending on storage capacity	15% efficiency ratio
Solar Utility Scale	5 to 250 MW	Daytime peaking load during sunny days	15% efficiency ratio
Solar DG (with storage)	<1 to 5 MW	Potential peaking load depending on storage	15% efficiency ratio
Solar DG	<1 to 5 MW	Daytime peaking load during sunny days	15% efficiency ratio
Fast Discharge Battery	<1 to 10 MW	Can provide instantaneous power for short periods	Variable, depending on efficiency, charging time and storage capacity
Slow Discharge Battery	10 to 20 MW	Can provide steady supply of power for short periods	Variable, depending on efficiency, charging time and storage capacity
Active DR - Emergency Generation	Variable (based on type of equipment and load)	Peaking load	Assume 15% of peak load becomes available to respond
Passive DR (Energy Efficiency)	Variable (based on type of equipment and load)	Intermittent	Assume 15% of peak load becomes available to respond

Note 1: Wind was not considered as a technically feasible NTA due to the lack of potential for sizeable wind capacity development in the Greater Boston region.

Note 2: Installed capacity range for fast and slow discharge batteries depends on the number of individual batteries connected together at a given site. The range indicated in the figure above is indicative, and LEI used variable sizes depending on requirements in order to ascertain the technical feasibility of using batteries as NTA technologies.

Note 3: Performance rates for CCGTs, Peaker Aeroderivative units, Peaker frame units and dual-fuel jet engines calculated based on the ISO New England EFORd Class Averages, sourced from: http://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf

Note 4: Active DR emergency profile is sourced from ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources." ISO-NE, November 7, 2014 http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

More details on the methodology and sources are provided in Appendix B.

In analyzing the potential for new energy efficiency as a technically feasible NTA technology, LEI assumed that at most 15% of the peak load can be expected to be reduced using new energy efficiency measures.[14]

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[14] According to the Utilities, achieving peak load reductions from energy efficiency of 15% *over and above levels achieved through state-mandated programs* is a goal that goes well beyond utility geo-targeting experiences to date. Eversource's Marshfield Distribution Relief Pilot (a targeted attempt to reduce 2 MW of demand on key circuits/substations through a combination of energy efficiency, direct load control, and solar PV installation) resulted in actual kW reductions of approximately 715 kW – less than 3% of peak day afternoon loads of 25,000 – 30,000 kW on the affected lines. Energy efficiency contributed only 320 kW of this load reduction. Similarly, National Grid's ongoing Tiverton/Little Compton Pilot targets load reductions of 1 MW (out of a total peak load of 20 MW) through a combination of energy efficiency and demand response. At the end of the 2014 (the third year of the pilot), approximately 566 kW of load reductions had been achieved, with approximately 426 kW coming from energy efficiency.

Operations profile for each NTA technology is used to determine when a given technology can operate during a 24 hour period. Both N-1 and N-1-1 contingency events require that a technically feasible NTA technology can operate for 12 hours. For each NTA technology listed in the figure above, its operations profile determines if it can meet the requirements posed by the contingency events. For example, while a peaker frame unit can operate for 24 hours, it may not be operating during off-peak night-time hours, which prevents it from a technically feasible NTA technology.

It bears noting that Real-Time Active DR ("RTDR"), which is typically associated with industrial or large commercial customer sites (such as manufacturing facilities or processing factories), were not directly taken into consideration in the analysis, although LEI still considered them as potential NTA technologies. There is a lack of publicly available information on RTDR's operational mode (such parameters will vary with equipment and size), timing and duration of operation, as well as response/ performance rates and opportunity costs, which does not allow us to model these technologies with confidence. Furthermore, under ISO-NE's rules, RTDR and real-time emergency generation ("RTEG") are not typically operable at any given time of the day, which would be a stumbling block to their technical feasibility under N-1-1 contingency events.[15] For reference purposes, LEI nevertheless estimated gross and net LCOE figures associated with both RTDR and RTEG in Appendix C.

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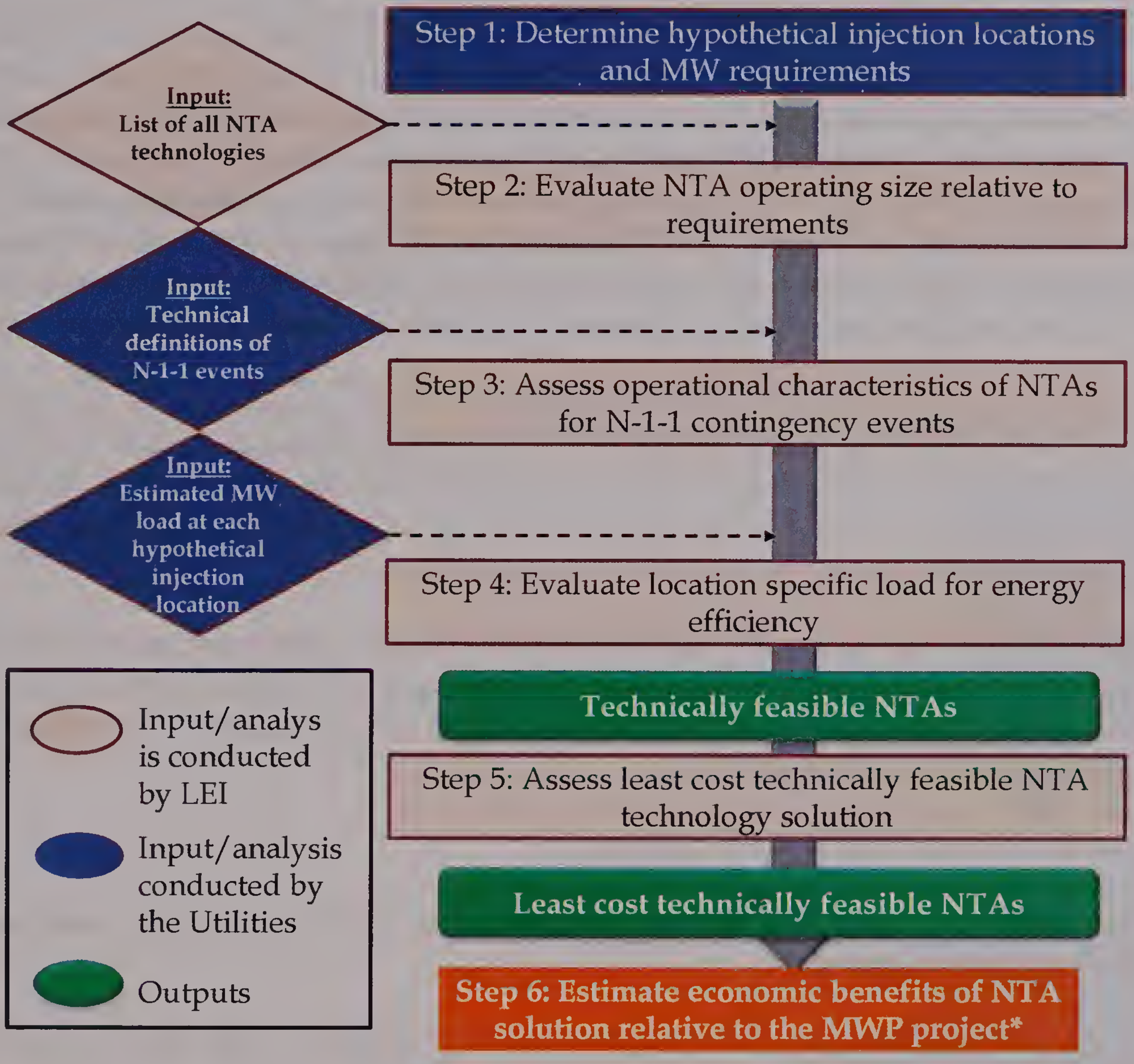
[15] " ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand

Resources, Asset Related Demands and Alternative Technology Regulation Resources." *ISO-NE, November 7, 2014* http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

4 Overview of Methodological Approach

In order to identify technically feasible NTAs that can satisfy the reliability issues being addressed by MWP, a six-phase methodology was designed. These phases are shown in Figure 10 below.

Figure 10. Methodological Approach


Step 1: Determine hypothetical injection locations and MW requirements
Input: List of all NTA technologies
Step 2: Evaluate NTA operating size relative to requirements
Input: Technical definitions of N-1-1 events
Step 3: Assess operational characteristics of NTAs for N-1-1 contingency events
Input: Estimated MW load at each hypothetical injection location
Step 4: Evaluate location specific load for energy efficiency
Technically feasible NTAs
Step 5: Assess least cost technically feasible NTA technology solution
Least cost technically feasible NTAs
Step 6: Estimate economic benefits of NTA solution relative to the MWP project*
Input/analys is conducted by LEI
Input/analysis conducted by the Utilities
Outputs

* Beyond the scope of this report

The objective of LEI's methodology to identify technically feasible NTAs (Phase 1 through 4 in the figure above) is to associate a technically feasible NTA technology for each location (substation) and injection amount (NTA requirement) specified by the Utilities. The methodology uses decision tree analysis to sequentially filter and narrow down the available list of technologies according to the requirements at each location. The three specific steps to achieve this are summarized below:

- Step A: Evaluate hypothetical injection points at substations to determine required size of NTA technologies (corresponds to Phase 2 in Figure 10);

- Step B: Compare the operational characteristics of NTA technologies against the requirements imposed by and the N-1-1 contingency events at each injection location (substation) (corresponds to Phase 3 in Figure 10);
- Step C: Assess the load available at each injection location in order to determine the feasibility of using certain NTA technologies like energy efficiency and demand response, which depend on the amount of available load (corresponds to Phase 4 in Figure 10).

The sequence of steps in this methodology is important because it assigns a technically suitable NTA technology to a given injection location through a staged process of selection. Step A of the methodology screens NTA technologies based on their sizes, which is analytically straightforward and effectively narrows the list of technically feasible NTA technologies for the subsequent steps. Step B evaluates the successfully screened NTA technologies based on their technical parameters and selects the ones that conform to the contingency event requirements. Steps A and B (in increasing order of analytical complexity), narrow down the list of technically feasible NTA technologies. In Step C, demand-side NTA technologies are further evaluated for feasibility based on load levels at the specific locations.

While LEI recognizes that there may be multiple NTA technologies that are feasible with each injection point/amount, the purpose of this analysis is to identify technically feasible NTA technologies that meet the criteria of the hypothetical NTA injections (either in terms of size, location, or operating profile).

In the next phase (phase 5 in Figure 10), the levelized cost methodology evaluates the direct cost of implementing NTA technologies for ratepayers as opposed to building and servicing the MWP. The direct cost is calculated by aggregating across all locations total costs estimated for each identified least cost technically feasible NTA technology.

4.1 Determination of hypothetical NTA solutions

The Utilities provided a summary of NTA requirements for MWP under three mutually exclusive hypothetical NTA solutions ("cases"):

- Small sized NTA technologies (NTA requirement, or "injection" less than or equal to 15 MW, designated "Pmax 15 MW" case)
- Medium sized NTA technologies (injection less than or equal to 250 MW, designated "Pmax 250 MW" case); and
- Large sized NTA technologies (injection less than or equal to 750 MW, designated "Pmax 750 MW" case)

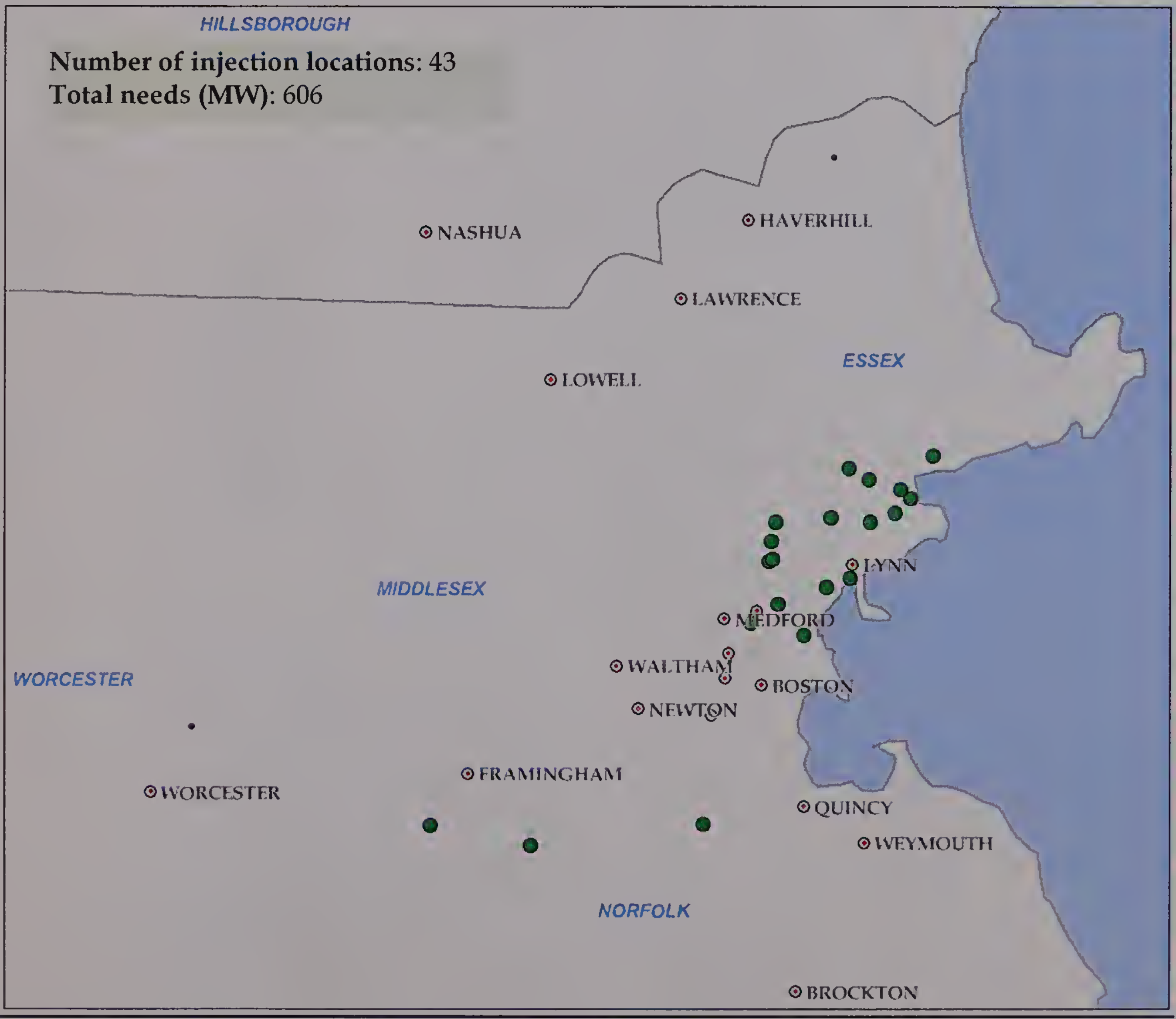
A summary of the requirements under each case is presented in Figure 11.

Figure 11. Summary of injection requirements for the hypothetical NTA solution for MWP across cases

Mystic - Woburn Project	Pmax 15 MW	Pmax 250 MW	Pmax 750 MW
Injection Locations (substations)	43	8	12
NTA Injection Requirements (MW)	606	445	552

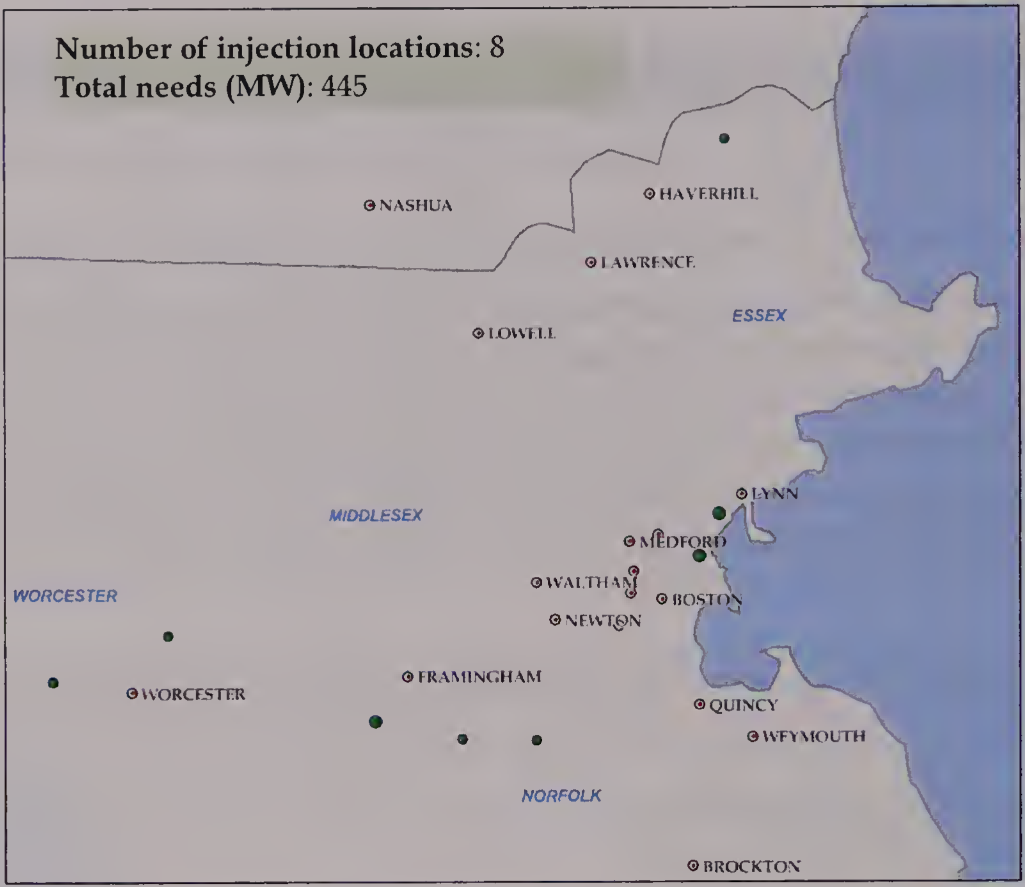
Figure 12, 13 and 14 each depict the relevant injection locations associated with the hypothetical NTA solution in each case. It is important to note that the number of injection locations for the small sized NTA technologies is considerably larger as compared to the other two cases. The injection locations for all cases are spread out around the Greater Boston Area. Appendix F provides a detailed description of assumptions and methodology underpinning the modeling exercise undertaken by the Utilities to determine the NTA requirements, which entails a set of injection amounts (MW) by location under N-1 and N-1-1 contingency events.

Figure 12. NTA requirements by location for small sized NTAs for MWP (Pmax 15 MW case)


HILLSBOROUGH
Number of injection locations: 43
Total needs (MW): 606
NASHUA
HAVERHILL
LAWRENCE
ESSEX
LOWELL
LYNN
MIDDLESEX
MEDFORD
WALTHAM
BOSTON
WORCESTER
NEWTON
FRAMINGHAM
WORCESTER
QUINCY
WEYMOUTH
NORFOLK
BROCKTON

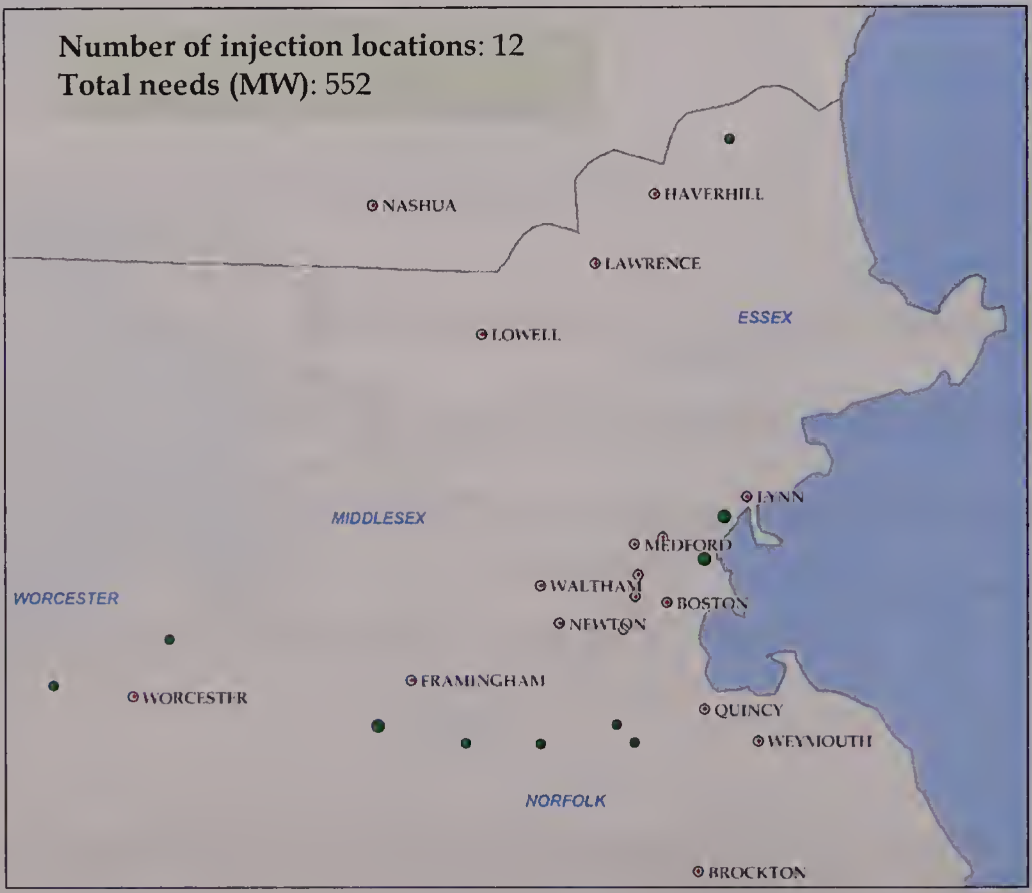
Counties in blue, closest large cities in red and injection points in green

Figure 13. NTA requirements by location for medium sized NTAs for MWP (Pmax 250 MW case)


Number of injection locations: 8
Total needs (MW): 445
NASHUA
HAVERHILL
LAWRENCE
ESSEX
LOWELL
LYNN
MIDDLESEX
MEDFORD
WALTHAM
BOSTON
WORCESTER
NEWTON
FRAMINGHAM
WORCESTER
QUINCY
WEYMOUTH
NORFOLK
BROCKTON

Counties in blue, closest large cities in red and injection points in green

Figure 14. NTA requirements by location for large sized NTAs for MWP (Pmax 750 MW case)


Number of injection locations: 12
Total needs (MW): 552
NASHUA
HAVERHILL
LAWRENCE
ESSEX
LOWELL
LYNN
MIDDLESEX
MEDFORD
WALTHAM
BOSTON
WORCESTER
NEWTON
FRAMINGHAM
WORCESTER
QUINCY
WEYMOUTH
NORFOLK
BROCKTON

Counties in blue, closest large cities in red and injection points in green

4.2 Methodology for identifying technically feasible NTA technologies

As summarized in the section above, LEI's methodology for identifying technically feasible NTA technologies uses a three-step process to evaluate and then select technically feasible NTA technologies for each NTA solution case for the MWP.

A technically feasible NTA technology is defined as one that can independently cater to all the requirements at the specific location. In other words, if at a location, two different technologies are required to work together (e.g. solar PV during the day and a CCGT at night) to meet the requirements, then neither of these technologies is determined to be technically feasible for this location on their own.[16]

However, a given location can have multiple NTA technologies that can each independently meet the NTA requirement. In such cases, the final selection from among the technically feasible NTA technologies at a given location is based on their levelized costs, as discussed further in Section 5.2 below.

When we use the term, "technically feasible", we are reflecting on a specific technology's ability to meet requirements set out by system planning criteria, and therefore in the case of this analysis, "feasibility" is not to be interpreted in the more connotative sense of the word (and the technologies may still be deemed to be impractical or commercially infeasible, as discussed in Section 5 of this report). System planning criteria refer to requirements such as the maximum allowable time for an NTA technology to respond to N-1-1 contingency events (response time)[17] and the minimum duration of time for which an NTA technology must remain operational after being called into service. In contrast, physical considerations, which are not a part of this methodology, refer to the amount of land required for a given NTA technology to be located at a substation and the time required for siting and construction, as well as the anticipated market need for the NTA technology in the future. These commercial development considerations outlined above are assessed qualitatively in Section 5.3. In addition, the cost implications of technically feasible NTA technologies are also assessed in detail in Section 5.2.

The three-step process is illustrated in Figure 15 and explained in the following sub-sections.

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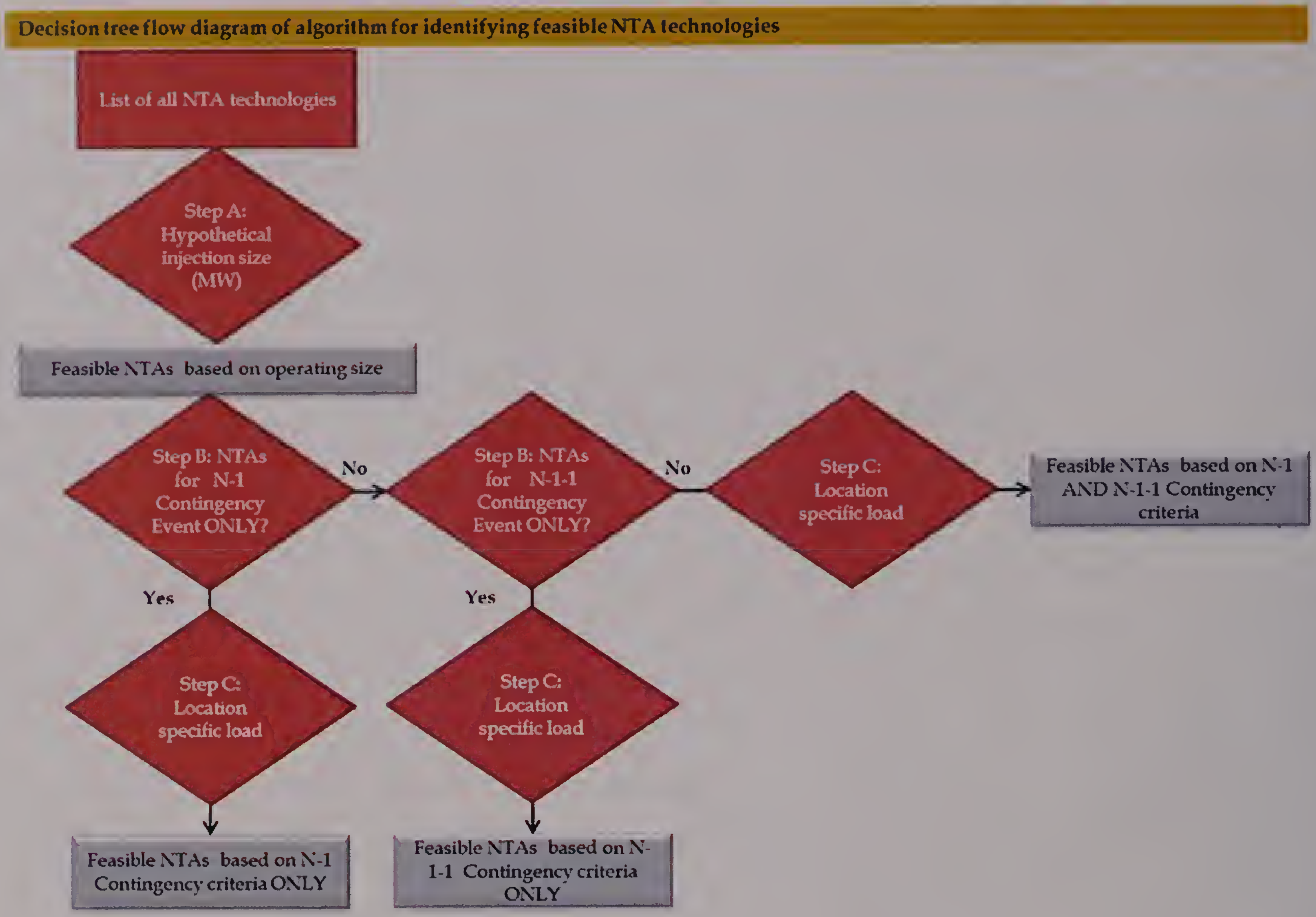
[16] The exception to this philosophy relates to solar PV technologies and energy storage. We do combine these two separate NTA technologies in order to form a third unique technology; energy storage enables the solar PV unit to qualify as a technically feasible NTA technology (if some of the production from day-time hours is stored so that it can be injected into the grid at night).

[17] See Step 2 for details on N-1 and N-1-1 contingency event requirements.

Figure 15. Methodology for identifying technically feasible NTA technologies


Decision tree flow diagram of algorithm for identifying feasible NTA technologies
List of all NTA technologies
Step A: Hypothetical injection size (MW)
Feasible NTAs based on operating size
Step B: NTAs for N-1 Contingency Event ONLY?
No
Step B: NTAs for N-1-1 Contingency Event ONLY?
No
Step C: Location specific load
Feasible NTAs based on N-1 AND N-1-1 Contingency criteria
Yes
Yes
Step C: Location specific load
Step C: Location specific load
Feasible NTAs based on N-1 Contingency criteria ONLY
Feasible NTAs based on N-1-1 Contingency criteria ONLY

Step A: Size

The first step focuses on the level or size of injection required by location or node. Upon reviewing commercial information provided by manufacturers (such as General Electric ("GE") or SIEMENS) on technologies size, and comparing the typical size of NTA technologies in operation in Massachusetts/Greater Boston region against the size of injection requirements at each location, it is possible to eliminate NTA technologies that are not suitable to the size of the injection. For example, in Pmax 15 MW case (for small scale NTA technologies), we can exclude conventional CCGT generation as a technically feasible NTA, as all the injection amounts are limited to no more than 15 MW in this hypothetical NTA solution. This first round of selection results in a preliminary list of technically feasible NTA technologies for each location (injection point) under each Case based on size (operating capability of the NTA). The maximum and minimum sizes considered for each NTA technology are summarized in Figure 9.

Step B: Operational

Based on the preliminary list of technically feasible NTA technologies from step A, we then move to consider the operating characteristics of the remaining NTA technologies relative to the requirements of the NTA injection amounts. These operating characteristics refer to the two contingency conditions defined by the Utilities for selected N-1 and N-1-1 events.

The N-1 and N-1-1 contingency events have associated operational considerations that must be met by a technology in order to be considered a technically feasible NTA technology. It bears noting that in the absence of MWP, N-1 contingency events could be resolved without the participation of NTA technologies; only N-1-1 events are of concern. However the selection process was designed to solve situations where NTA requirements would also emerge under N-1 contingency events. An N-1 contingency event refers to a situation when a single element of the generation or transmission system fails. Under such circumstances, technically feasible NTA technologies would need to provide energy within 5 minutes and continue to operate until the single element is repaired or as long as deemed necessary by the ISO-NE. Similarly, an N-1-1 contingency event refers to a situation where an additional single element of the generation or transmission system fails within 30 minutes of the N-1 contingency event. Under these circumstances, a qualified NTA technology must be able to provide energy within 30 minutes and must continue to do so until the elements are repaired or as long as deemed necessary by the ISO-NE (typically, ISO-NE can resolve contingency events within a 12 to 24 hour cycle; LEI has assumed a 12 hour duration to resolve each of the contingency events in its analysis.

In addition, the Utilities have provided an estimate of the CLL. LEI uses the CLL to determine when it is likely that an N-1 contingency would result in system instability. Therefore LEI begins the analysis of N-1 contingency events by looking at the hourly forecasted load profile of the Greater Boston zone and comparing the hourly load to the CLL value provided by the Utilities. The frequency of hourly load exceeding the CLL then defines the time of day and season when NTA technologies would likely be required to operate to prevent reliability problems should a contingency event occur during those periods.[18] Detailed assumptions on the technical and operational characteristics of NTA technologies and how these relate to the contingency event and CLL are described in Appendix B.

In light of the requirements defined by these contingency events, Step B selects NTA technologies that are able to respond within the time-frame required, and are able to continue injecting energy reliably for the duration required by these contingency events.

Step C: Locational

The last step further refines this list of technically feasible NTA technologies by using locational considerations at each injection location for each Case. For two specific NTA technologies - active demand response and passive demand response (energy efficiency), this step of the methodology compares the total load (MW demand) at each injection location against the NTA requirement at that location. This comparison reveals whether a particular location has sufficient demand that can be curtailed either through active demand response or by implementing new energy efficiency measures so that the NTA requirement at that location can be met. The underlying assumption is that up to 15%

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[18] See Appendix B for the forecasted hourly load in the Greater Boston zone, as provided to LEI by the Utilities

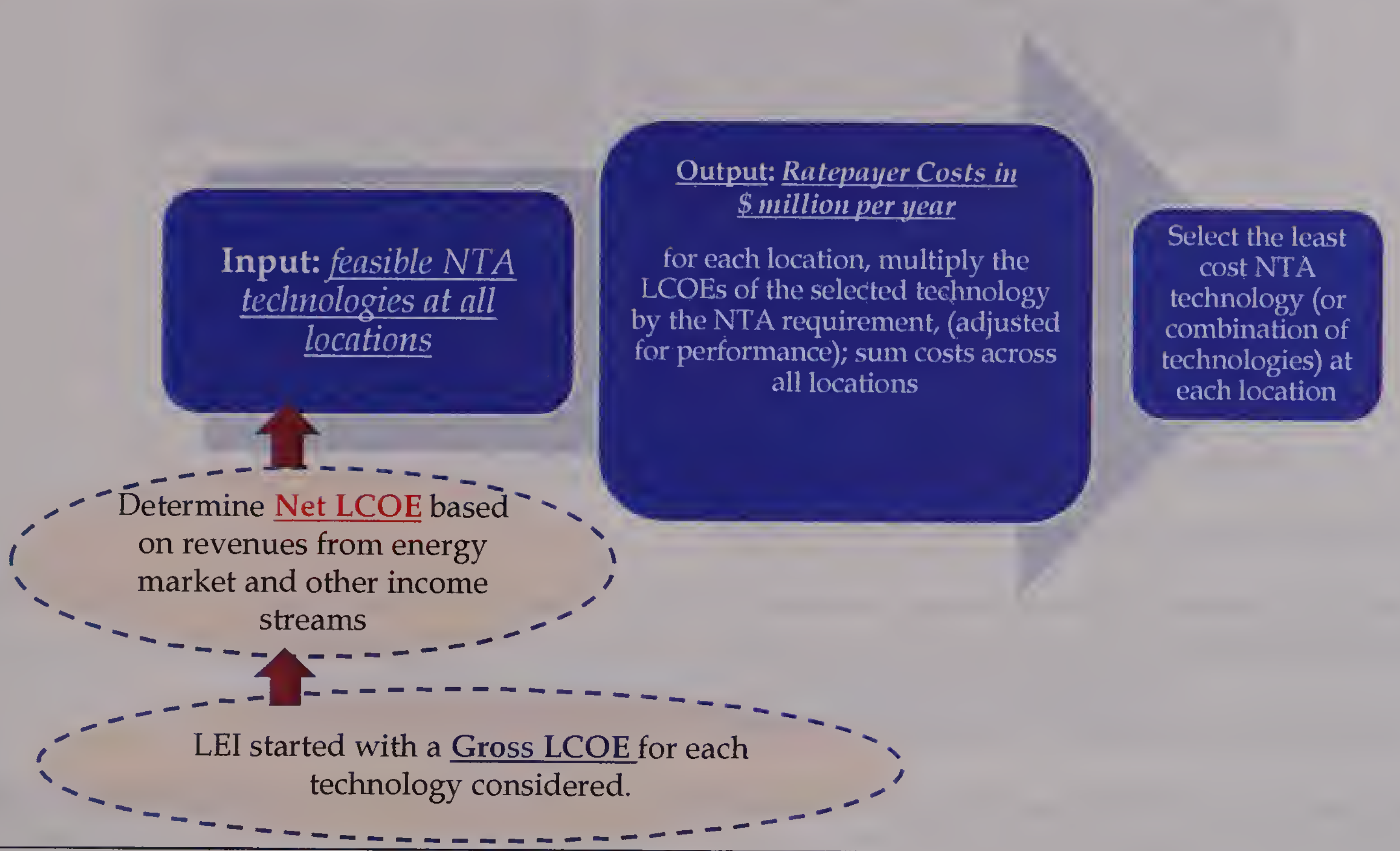
of peak load at any given location can be reduced using new energy efficiency programs. This parameter was developed in conjunction with the Utilities. Achieving peak load reductions from energy efficiency of 15% over and above levels achieved through state-mandated programs is a goal that goes well beyond utility geo-targeting experiences to date. Eversource's Marshfield Distribution Relief Pilot (a targeted attempt to reduce 2 MW of demand on key circuits/substations through a combination of energy efficiency, direct load control, and solar PV installation) resulted in actual kW reductions of approximately 715 kW – less than 3% of peak day afternoon loads of 25,000 – 30,000 kW on the affected lines. Energy efficiency contributed only 320 kW of this load reduction. Similarly, National Grid's ongoing Tiverton/Little Compton Pilot targets load reductions of 1 MW (out of a total peak load of 20 MW) through a combination of energy efficiency and demand response. At the end of the 2014 (the third year of the pilot), approximately 566 kW of load reductions had been achieved, with approximately 426 kW coming from energy efficiency.

The results of this three-step methodology were then used as direct inputs into the cost analysis.

4.3 Methodology for estimating cost of technically feasible NTA technologies

LEI employed industry-standard levelized costing principles to the identified pool of technically feasible NTA technologies from step 3 above in order to estimate the total cost of implementing the least cost technically feasible NTA technologies for each hypothetical NTA case (Pmax 15 MW, Pmax 250 MW and Pmax 750 MW cases). For each selected technology, LEI estimated a gross LCOE which, represents a resource' all-in-costs, levelized over its life cycle. The gross LCOE is a per kilowatt per year figure ($/kW-year) that embodies all costs including capital costs, going-forward FOM costs, as well as fuel and VOM costs. The gross LCOE represents a long term timeframe that is consistent with the requirements identified at each injection point. As a next step, LEI derived Net LCOE for each technology by deducting from gross LCOE a bundle of potential revenue streams associated with each NTA technology. The analysis then consisted of multiplying at each injection point the net LCOEs of all feasible technologies by the NTA capacity requirements (adjusted for performance and availability). The least cost technically feasible NTA technologies were selected at each location by comparing the products of net LCOEs and NTA capacity requirements across all feasible technologies. Finally, we aggregated the total costs associated with the identified least cost technically feasible NTA technologies across all locations in order to determine net direct cost for the ratepayers. Figure 16 provides an illustration of the methodology.

Figure 16. Methodology for estimating net direct costs of technically feasible NTA technologies ($/kW-year)


Input: feasible NTA technologies at all locations
Output: Ratepayer Costs in $ million per year
for each location, multiply the LCOEs of the selected technology by the NTA requirement, (adjusted for performance); sum costs across all locations
Select the least cost NTA technology (or combination of technologies) at each location
Determine Net LCOE based on revenues from energy market and other income streams
LEI started with a Gross LCOE for each technology considered.

4.3.1 Determining gross LCOE for technically feasible NTA technologies

Gross LCOE represents the total fixed cost of NTA technologies levelized over the lifetime of the relevant technologies. As discussed previously, gross LCOE includes capital costs, fuel costs, as well as both FOM and VOM. Gross LCOE is denominated in $/kW per year and then multiplied by the installed capacity of the technically feasible NTA technologies to yield an annual gross cost. Figure 17 provides a summary of calculated gross LCOE for all technologies deemed technically feasible. For cost information, LEI relied primarily on data made publicly available by ISO-NE and the state of Massachusetts. We then cross-compared and supplemented this data with information collected from reputable sources, such as the US Department of Energy and affiliated national laboratories, manufacturers and engineering procurement companies that work with such technologies , as well as actual operating data from similar installations across New England.

Appendix C provides a detailed description of assumptions and sources used for determining the ranges of gross LCOEs. LEI defined a +/- 20% range of gross LCOE to take into consideration the uncertainty associated with cost assumptions. In fact, in real life, development and operation costs of facilities can vary significantly and deviate from a generic assumption due to a variety of reasons including plant location, financing structure and market conditions, technology types, labor cost, environmental cost, site preparation, fuel supply, etc. The cost range was suggested in an attempt to crystallize this uncertainty. The +/-20% cost range was used to measure the impact of this uncertainty on the net direct costs of technically feasible NTA solutions.

Figure 17. Summary of Gross LCOE per technology

Feasible Technologies	Gross LCOE ($/kW-y)	Range ($/kW-Y) +/- 20%	
CCGT	$ 397.8	$ 318.3	$ 477.4
Peaker Aeroderivative	$ 323.4	$ 258.7	$ 388.1
Dual fuel jet engine	$ 362.9	$ 290.3	$ 435.5
Slow Discharge Batteries	$ 181.4	$ 145.1	$ 217.7
Solar Utility Scale (with storage)	$ 415.9	$ 332.7	$ 499.1
Passive DR (Energy Efficiency)	$ 424.2	$ 339.3	$ 509.0

Note: This table presents the mid values of the estimated ranges

Sources: ISO-NE, National Renewable Energy Laboratory ("NREL"), Pacific Northwest National Laboratory ("PNNL"), International Energy Agency, Electric Power Research Institute ("EPRI"), Department of Energy and LEI

4.3.2 Determining Net LCOE for technically feasible NTA technologies

The total gross cost of NTA technologies can be defrayed by market revenues and other sources of income received by these resources when they begin operations. Although these revenues are passed through to customers in the form of cost through the supply portion of their utility bill, these costs would have to be borne by customers regardless of whether a resource is qualified as a technically feasible NTA technology or not. Therefore we deduct these revenues from the gross LCOEs, so as to isolate the net direct costs to ratepayers for a technically feasible NTA solution. In this respect, LEI adjusted the gross LCOE analysis by incorporating a number of potential market revenue streams associated with each feasible technology. The resulting calculation is the net LCOE which is relied upon to evaluate net direct cost of implementing technically feasible NTA technologies for ratepayers. The revenue streams considered in this analysis include revenues from the energy and capacity markets, Local Forward Reserve Market ("LFRM") and Regulation Market revenues, income associated with avoided retail rate costs (for solar DG and energy efficiency resources), as well as Renewable Energy Credits. However, we did not integrate in the analysis any additional charges (such as Net Commitment Period Compensation ("NCPC") associated with operating the technologies out of merit.[19] Figure 18 depicts the revenue streams considered and provides a summary of calculated Net LCOE by feasible technology. Appendix C summarizes the sources relied upon to estimate the revenue offsets.

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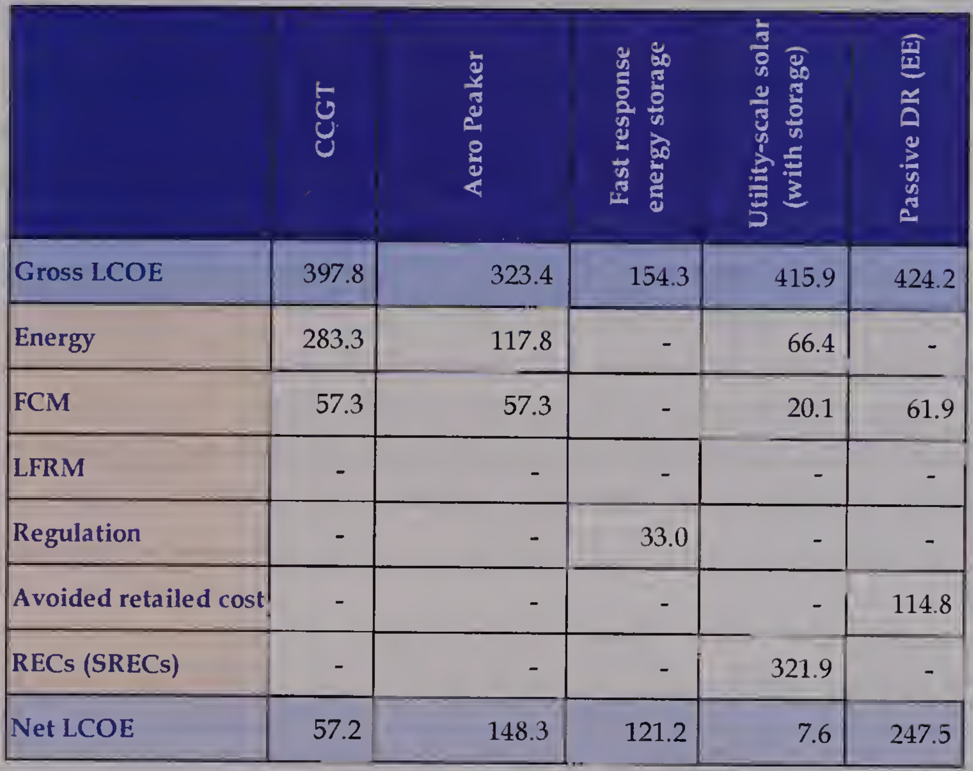
[19] NCPC is the additional compensation received by a resource that is committed for reliability purposes but not dispatched above its economic minimum output level.

Figure 18. Components of the net LCOE calculations for each technically feasible NTA technology ($/kW-year)



	CCGT	Aero Peaker	Fast response energy storage	Utility-scale solar (with storage)	Passive DR (EE)
Gross LCOE	397.8	323.4	154.3	415.9	424.2
Energy	283.3	117.8	-	66.4	-
FCM	57.3	57.3	-	20.1	61.9
LFRM	-	-	-	-	-
Regulation	-	-	33.0	-	-
Avoided retailed cost	-	-	-	-	114.8
RECs (SRECs)	-	-	-	321.9	-
Net LCOE	57.2	148.3	121.2	7.6	247.5

Notes: This table illustrates net LCOEs for a scenario assuming half of FCM payments are received by the resources and SREC prices are at similar level as 2017 forwards. Rows highlighted in pink represent revenue offsets, while the bottom blue row contains the net LCOE results from the realization of all of these revenue offsets

FCM price based on FCA#9 results ($9.55/kW-month) (before adjustment for derating factor and scenario)
Energy revenues inclusive of VOM and fuel cost recovery (base energy price (without fuel and O&M cost recovery) for 2018 forecasted at $504/MWh)
LFRM ($/MW-month) for summer 2013: $2,996; LFRM ($/MW-month) for winter (2013/2014): $5,501
Annual average regulation price (without performance payment in 2013):$18/MWh
Avoided retail cost: (based on average residential retail rate) $17.6/MWh
SREC: 2017 forward price ($245/MWh); ACP for Class I REC ($67/MWh)

Sources: ISO-NE, NREL, PNNL, IEA, EPRI, DOE and LEII

5 Analysis and results

Of the total twelve NTA technologies under consideration, six technologies qualify as technically feasible NTA technologies for the MWP under the three cases examined. Under the small sized NTA case, peaker aeroderivative units, utility scale solar (with energy storage) slow discharge batteries and dual-fuel jet engines are the most common NTA technologies. Energy efficiency also qualifies as technically feasible NTA technologies at select locations that have NTA injection requirements are reasonable given the load at that location.

For medium and large sized NTA cases (Pmax 250 MW case and Pmax 750 MW case), CCGTs, and to a lesser extent, peaker aeroderivative and slow batteries are the predominant technically feasible NTA technology due to the large injection requirements under these two cases. Technologies like fast discharge batteries, solar PV (DG and utility scale) without storage and peaker frame units are among the technologies that never qualify as technically feasible NTA technologies owing to their various technical characteristics.

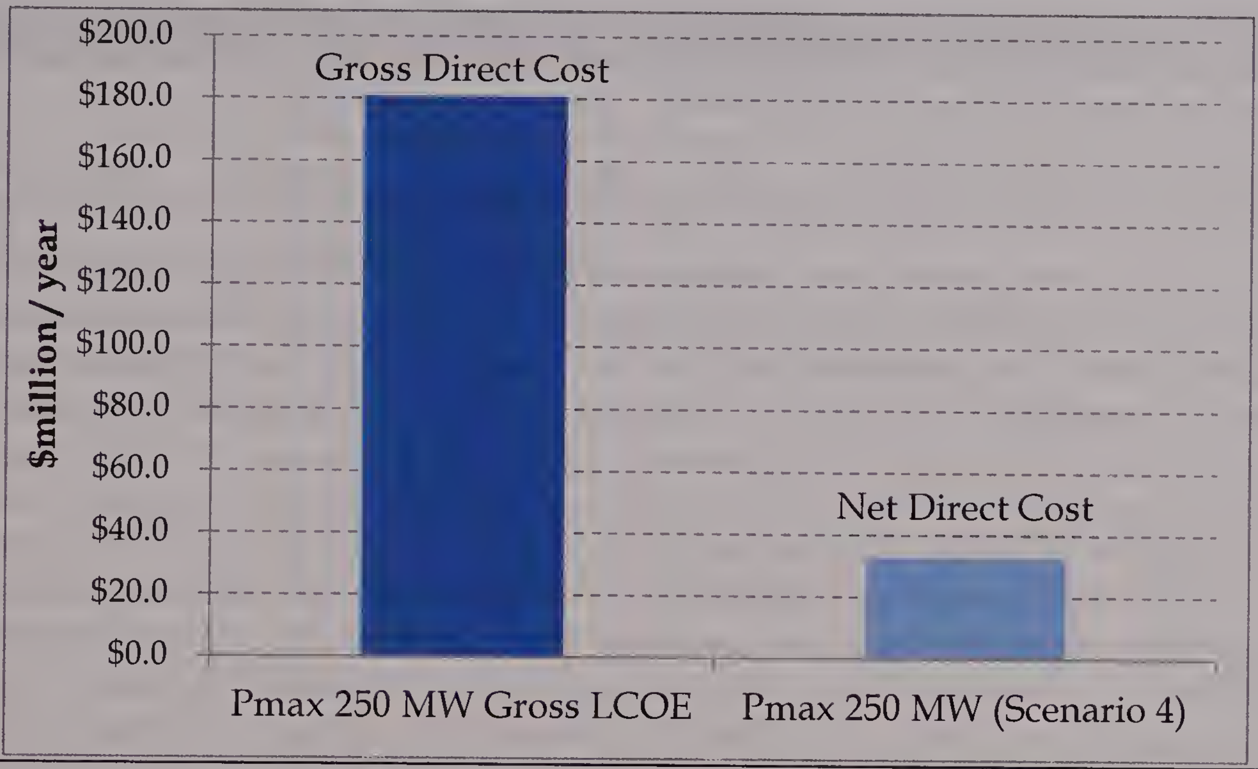
The injection amounts associated with these technologies need to be converted into an installed capacity figure using the performance rates for each individual technology (e.g., availability factor for thermal technologies, conversion efficiency for solar units and batteries). Therefore a requirement of 1 MW may actually require installed capacity that exceeds 1 MW. Furthermore, since more than one NTA technology can be technically feasible for a given location, the installed capacity of all the technically feasible technologies can be significantly larger than the NTA requirement at that location, as there are multiple feasible technologies that are possible at many locations. For example, the NTA requirements of between 445 MW and 606 MW across the three cases translates into installed capacity of technically feasible NTA technologies between 5,417 MW to over 15,000 MW. These large figures do not themselves suggest a specific NTA solution per se, but they do demonstrate the variety of NTA technologies that are possible and that the installed capacity would have to be higher than the requirement in order to account for expected performance.

The cost analysis begins with the evaluation of total cost of technically feasible technologies based on gross LCOE and estimated required nameplate capacity. Under the baseline gross LCOE, annual gross costs for a technically feasible NTA solution for MWP were estimated to range between $181 million and $231 million across the three cases (Pmax 15 MW, Pmax 250 MW and Pmax 750 MW). When adding a +/- 20% sensitivity on gross LCOEs, the resulting gross costs range from $145 million to $277 million a year.

LEI recognized that total costs of NTA technologies can be defrayed by revenues from markets as well as other sources. Therefore, in estimating the cost of a feasible NTA solution, LEI deducted expected notional market revenues from the gross costs to derive a net LCOE. The net LCOE multiplied by the required nameplate capacity for the technically feasible NTA technologies completes the process of estimating the net direct cost to ratepayers.

The primary uncertainty in estimating the net LCOE is the revenue forecast for each technology. The future expected revenues were projected based on existing market information.[20] In summary, the range of net direct cost was estimated at $26 million to $147 million per year over the various scenarios and the three cases. However, some scenarios and NTA solutions (cases) are very unlikely from a practical and markets perspective. Based on a methodical consideration of the likely market revenues achievable over the life of an asset, scenario 4 (where we are modeling a low SREC revenues and capacity payments for 50% of the economic life of the technically feasible NTA technologies) is the most probable. The case that produces the lowest net direct cost to ratepayers under scenario 4 and is the most practical from a development perspective is the Pmax 250 MW case, where the technically feasible NTA technologies are primarily CCGTs. Under this scenario and case, the net direct cost to ratepayers is estimated at $33 million a year, which is significantly more than the annual revenue requirements for MWP (approximately $10 million). Under a +/- 20 % range in gross LCOE, the estimated net direct cost under Pmax 250 MW case – scenario 4 would range between $26 million and $39 million a year.

Figure 19. Illustration of gross and net direct cost for the most probable case for MWP (Pmax 250 MW case)



5.1 Technically Feasible NTA technologies

Selection of technically feasible NTA technologies for the MWP is divided into three cases based on the maximum size of the injections at each substation. These cases are:

- Small sized NTA technologies (Pmax 15 MW case);
- Medium sized NTA technologies (Pmax 250 MW case); and

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[20] A detailed modeling analysis would be required to further refine these revenue estimates and factor in the resources' year on year impacts on market conditions and how that, in turn, affects market prices; such an analysis is beyond the scope of this report.

- Large sized NTA technologies (Pmax 750 MW case).

Based on the analysis conducted by the Utilities, the injection amount (sum of NTA MW injections across locations) associated with each case varies, which affects the choice of technically feasible NTA technologies. The different cases considered for an NTA solution for the MWP produce distinct injection requirements. These requirements differ both in terms of number of injection locations, as well as the MW amounts needed. Figure 20 summarizes the NTA requirements on an aggregated basis across the three cases. The injection amount or requirement is in capacity (MW terms) but also effectively represents an amount of energy that would be needed to be injected into the system at a given moment in time in order to ensure reliable operations during contingency events. In order to ensure that amount of energy would be available when needed to meet the reliability requirements, the installed capacity of a technically feasible NTA technology in most cases needs to be higher than this requirement in order to account for operating performance of such NTA technologies under real world conditions.

Figure 20. Summary of injection requirements for the three NTA solutions tested for MWP

Mystic - Woburn Project	Pmax 15 MW	Pmax 250 MW	Pmax 750 MW
Injection Locations (substations)	43	8	12
NTA Injection Requirements (MW)	606	445	552

Based on the technical and operational requirements at injection locations, and corresponding capabilities of the NTA technologies, Figure 21 presents a summary of the technically feasible NTA technologies for each case. The numbers in each cell are aggregate totals across all locations for a given case. As a result, the numbers in this figure indicate the aggregate total MW injection that can be supplied by a given technically feasible NTA technology across all locations. The table also has a row at the bottom that denotes the total injections required based on the Utilities' analysis. As can be seen, some technically feasible NTA technologies can, on their own, fulfill the entire NTA requirement. It is important to note that the numbers in Figure 21 are not adjusted for the effective installed capacity of each of the NTA technologies. For example, under the Pmax 15 MW case, the 606 MW of utility scale solar units under N-1-1 conditions refers to the actual amount of power required. Assuming a 15% annual average capacity factor, the effective size of a utility scale solar unit that can generate 606 MW in any given hour would need to be 4,042 MW in nameplate capacity terms. As such, the figure below does not take into account the practical considerations associated with nameplate capacity ratings associated with the required amount of NTAs in the Greater Boston region, nor does it factor in the associated cost estimates. The adjustment for operating performance and availability (in essence, the re-calculation of the nameplate capacity) and the cost estimates of feasible NTA technologies are detailed in the next section of this report.

Figure 21. Amount of NTA requirements by case and technically feasible NTA technology for MWP

	Mystic-Woburn MW Injections					
	Pmax = 15		Pmax = 250		Pmax = 750	
NTA Resource	N-1 (MW)	N-1-1 (MW)	N-1 (MW)	N-1-1 (MW)	N-1 (MW)	N-1-1 (MW)
Combined Cycle Gas Turbine (CCGT)	0	0	0	393	0	393
Peaker Aeroderivative Unit	0	606	0	154	0	261
Peaker Frame Unit	0	0	0	0	0	0
Dual-fuel Jet Engine	0	454	0	6	0	15
Solar Utility Scale (with storage)	0	606	0	52	0	74
Solar Utility Scale	0	0	0	0	0	0
Solar DG with storage	0	0	0	0	0	0
Solar DG	0	0	0	0	0	0
Fast Discharge Battery	0	0	0	0	0	0
Slow Discharge Battery	0	606	0	279	0	386
Active DR - Emergency Generation	0	0	0	0	0	0
Passive DR (Energy Efficiency)	0	19	0	6	0	5
Cumulative NTA resource requirements provided by Utilities	0	606	0	445	0	552

The last row of the figure provides the total MWs required from a technically feasible NTA solution (for N-1 and N-1-1 contingency events). As can be seen, under the N-1-1 event for Pmax 15 MW case, for example, peaker aeroderivative units, slow discharge batteries and utility scale solar PV (with storage) can each meet the cumulative NTA resource needs. The final choice of which of these NTA technologies will be selected for the cost analysis at each injection location will be determined on the basis of each technology's net levelized costs (net LCOE).

The results presented above incorporate the assumption that energy efficiency can at most reduce peak load by 15% (assuming a participation rate close to 100%) at any given injection location, which restricts the amount of energy efficiency that can qualify as a technically feasible NTA technology at many locations.

Other small scale NTA technologies, such as distributed solar generation ("solar DG"), cannot effectively meet the technical requirements of the contingencies and the sizing required of hypothetical NTA requirements at the various locations. For example, solar DG resources have an operating profile that does not provide for the sustained performance required under N-1 and N-1-1 contingency events. Even if solar DG were to be paired with energy storage technologies (battery) to overcome the intermittency of operation, LEI's methodology was not able to qualify solar DG units as technically feasible NTA technology because of the very small amount of the power that a typical 5 MW solar DG unit can produce. Specifically, in Massachusetts, a solar DG unit is conventionally defined as less than 5 MW of nameplate capacity and exhibits an average performance rate of 15%[21], implying that a 5 MW unit would only produce 0.75 MW of energy on average. There were no locations with an NTA requirement of such a small size in the three cases prepared by the Utilities. Of course, it is possible to add more than one stand-alone solar DG project to a given grid location (sub-station). However, there is some uncertainty as to the maximum number of feeder connections that could be allowed at any given sub-station.[22] Considering that utility scale solar PV resources (with energy storage) have the same performance profile as solar DG resources (with energy storage), the selection of utility scale solar PV resources can also proxy for a situation where several solar DG installations *could* serve as a technically feasible NTA (although such a combination of multiple solar DG installations would operate at a higher cost than the utility scale (notably, the gross LCOE is on average 40% lower for utility-scale solar PV as compared to solar DG)). In effect, a larger sized utility scale solar PV project mimics the presence of several smaller solar DG units at the same location.

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[21] We assumed an annual average capacity factor of 15% for solar PV in Massachusetts based on modeling results as documented in NREL's System Advisor Model. An annual average capacity factor of 15% is consistent with the state of Massachusetts' estimated solar PV's capacity factor of 13% (see "SREC project calculation", Massachusetts Energy and Environmental Affairs - Department of Energy Resources). It is worth noting that the annual average capacity factor that is required for assessment of performance in LEI's analysis is distinct from 35% derating factor that ISO-NE is currently assuming for its analysis of solar DG. The 35% derating factor is used to determine a capacity contribution from such resources in ISO-NE's planning documents and therefore it represents the potential performance only during the summer super-peak hour rather than the average performance across all hours that is measured by an annual capacity factor (see 2014 Interim Forecast of Solar Photovoltaic (PV) Resources, ISO-NE). For assessing the technical feasibility of a technology to meet

Detailed results for technically feasible NTA technologies at each injection location under each case, including the instances described above, are presented in Appendix D.

5.1.1 Distribution of technically feasible NTA technologies across hypothetical injection locations

In addition to the total MWs associated with each technically feasible NTA technology, it is also useful to look at the total number of hypothetical injection locations (substations) where a certain type of NTA technology is feasible. For example, of the 43 hypothetical injection locations identified by the Utilities under the Pmax 15 MW case, slow discharge batteries, peaker aeroderivative units and utility scale solar units qualify as technically feasible NTA technologies at all 43 locations, whereas dual-fuel jet engines only qualify at 74% of locations (32 locations). The share of technically feasible NTA technologies by location as a percentage of total number of hypothetical injection locations under each case is presented in in Figure 22.

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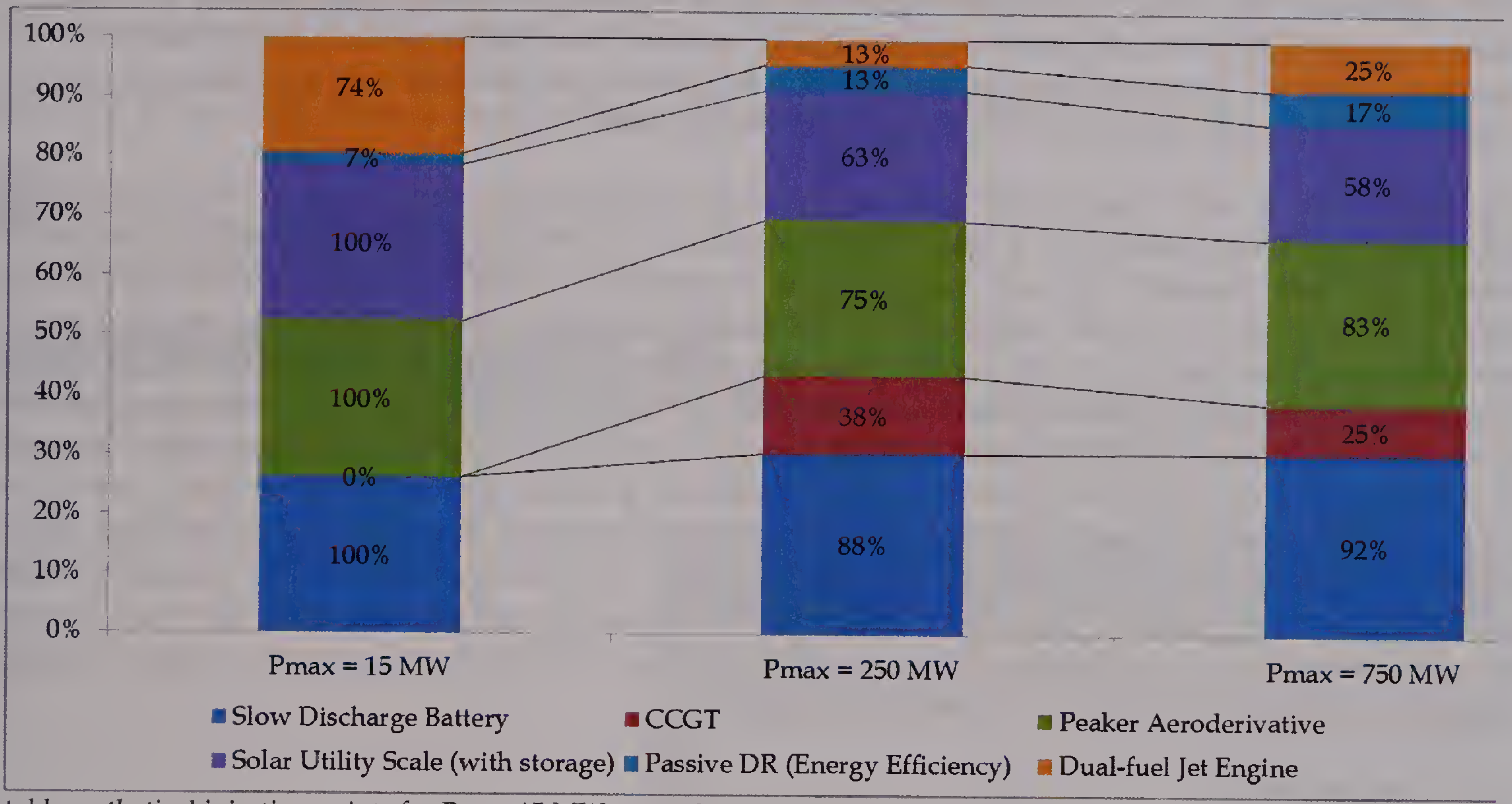
the NTA requirements, LEI employs the annual capacity factor as contingency events can occur anytime – not just during the summer super-peak. In the net direct costs analysis, LEI uses both the annual capacity factor and the 35% derating factor.

[22] A comprehensive system impact study was beyond the scope of the current work plan, and would have been necessary, according to the Utilities' experts, to establish the precise number of feeders that could be viable at every location.

Figure 22. Share of technically feasible NTA technologies by location as a percentage of total number of hypothetical injection points under each case for MWP



Total hypothetical injection points for Pmax 15 MW case: 43
Total hypothetical injection points for Pmax 250 MW case: 8
Total hypothetical injection points for Pmax 750 MW case: 12

There are several interesting observations that emerge from reviewing Figure 22. A number of technologies such as peaker aeroderivative and slow discharge batteries remain technically feasible NTA technologies at a majority of locations across the three cases, owing to their flexible operational profiles. Utility scale solar PV units (with storage) also feature prominently as technically feasible NTA technologies - at almost half of all locations for each of the cases due to similar characteristics like the ability to run at all hours, operate continuously for 12 hour duration required for the contingency events and inject sufficient energy to meet the requirements at various locations. CCGT technology is completely infeasible in the small sized NTA case (Pmax 15 MW case) because the injection amounts are too small for this technology to operate economically given current minimum scale applications for this technology.[23] In contrast, CCGTs appear frequently as a technically feasible technology under Pmax 250 MW and Pmax 750 MW cases. Energy efficiency is a technically feasible NTA technology only at limited locations that have sufficiently large load. New and additional energy efficiency programs are incrementally more difficult to implement.

The Utilities estimated at 15% the maximum percentage of peak load reduction achievable at a given location through incremental new programs.[24] Therefore, in the analysis, only locations that have injection requirements smaller than 15% of the peak load at those locations would be available for new energy efficiency. For example, if a location has a peak load forecast of 80 MW, then given the ability of energy efficiency programs to reduce peak load by 15% (taking into account existing and already planned energy efficiency programs), only 12 MW will be available as a technically feasible NTA. Therefore, if the NTA requirement at that location is greater than 12 MW, energy efficiency will not qualify as a technically feasible NTA technology at that location.

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[23] The typical size of CCGT plants in New England is 250-300 MW. Source: CELT 2014 from ISO-NE.

[24] According to the Utilities, achieving peak load reductions from energy efficiency of 15% *over and above levels achieved through state-mandated programs* is a goal that goes well beyond utility geo-targeting experiences to date. Eversource's Marshfield

It is important to note that energy efficiency, while traditionally considered a small-scale NTA technology, does not qualify as a technically feasible NTA technology as frequently as expected because the load available at each substation is frequently too small to provide enough energy efficiency savings as to meet the required NTA MWs at that location. We assume that peak load at any substation could be reduced by up to 15% through maximum participation in *new* energy efficiency programs - incremental to those assumed in the ISO-NE CELT forecast. This is already an aggressive assumption considering the significant existing energy efficiency programs in Massachusetts. In order for energy efficiency to become feasible at more locations, a higher penetration percentage would be required. LEI conducted a hypothetical test and determined that more than 55% of the peak load would need to be reduced in order for energy efficiency to work as a technically feasible NTA at just 50% of all locations under the Pmax 15 MW case. 55% is obviously an unrealistic target for any new energy efficiency program, and highlights the practical difficulties of implementing new energy efficiency programs to provide for technically feasible NTA solutions.

5.2 Cost estimates

The goal of the cost analysis is to evaluate the net direct cost of implementing NTA technologies for ratepayers as opposed to building MWP. The analysis begins with the evaluation of total cost of technically feasible technologies based on gross LCOE and nameplate capacity, followed by a net LCOE analysis which leads to an estimate of the net direct costs to ratepayers.

5.2.1 Gross cost estimates for ratepayers

Under the base line gross LCOE, gross cost for ratepayers is estimated to range between $181 million and $231 million a year across the three cases (Pmax 15 MW, Pmax 250 MW and Pmax 750 MW). When adding a +/- 20% sensitivity, the resulting gross direct cost falls within a range of $145 million to $277 million a year. The cost analysis was done across all considered cases (Pmax 15 MW, Pmax 250 MW, and Pmax 750 MW cases); for each injection point, under a given case, we calculated the total cost for all identified technically feasible NTA technologies based on the combination of their respective gross LCOE and total nameplate capacity requirements (at the injection location) - adjusted for operating factors.[25] At each location, the resulting costs across all technically feasible NTA technologies was

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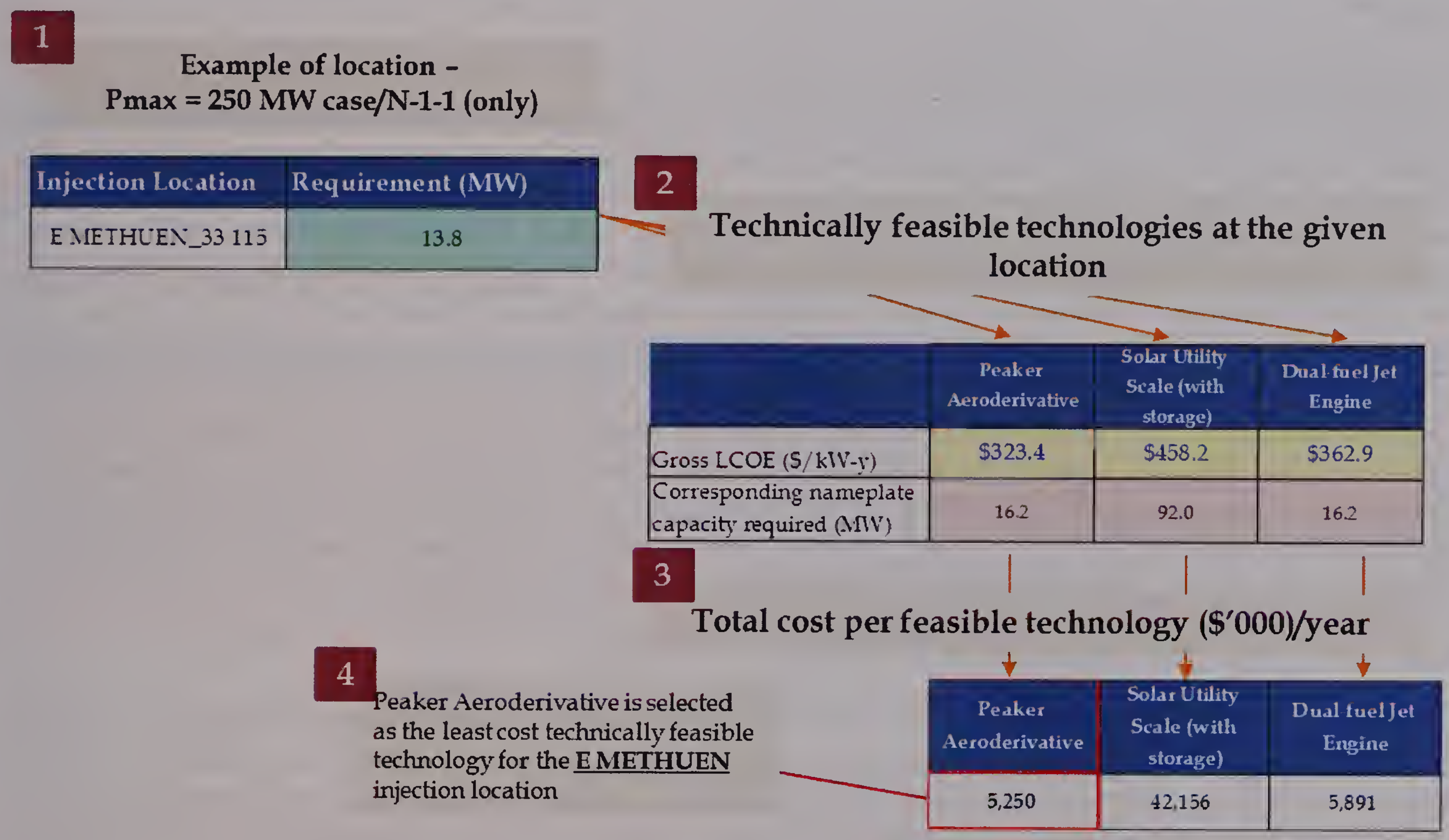
Distribution Relief Pilot (a targeted attempt to reduce 2 MW of demand on key circuits/substations through a combination of energy efficiency, direct load control, and solar PV installation) resulted in actual kW reductions of approximately 715 kW – less than 3% of peak day afternoon loads of 25,000 – 30,000 kW on the affected lines. Energy efficiency contributed only 320 kW of this load reduction. Similarly, National Grid's ongoing Tiverton/Little Compton Pilot targets load reductions of 1 MW (out of a total peak load of 20 MW) through a combination of energy efficiency and demand response. At the end of the 2014 (the third year of the pilot), approximately 566 kW of load reductions had been achieved, with approximately 426 kW coming from energy efficiency.

[25] Operating factors include capacity factor, availability factor and ramping rates.

compared in order to determine the corresponding least cost NTA technology per location, given the technology's specific gross LCOEs. Finally costs were aggregated for all identified least cost technically feasible NTA technologies across all injection locations to derive the overall total gross cost of each NTA solution per case. LEI then tested both higher (+20%) and lower (-20%) gross LCOEs.

Figure 23. Illustration (in four steps) of least cost technically feasible technologies selection



1 Example of location – Pmax = 250 MW case/N-1-1 (only)

Injection Location	Requirement (MW)
E METHUEN_33 115	13.8

2 Technically feasible technologies at the given location

	Peaker Aeroderivative	Solar Utility Scale (with storage)	Dual-fuel Jet Engine
Gross LCOE ($/kW-y)	$323.4	$458.2	$362.9
Corresponding nameplate capacity required (MW)	16.2	92.0	16.2

3 Total cost per feasible technology ($'000)/year

Peaker Aeroderivative	Solar Utility Scale (with storage)	Dual fuel Jet Engine
5,250	42,156	5,891

4 Peaker Aeroderivative is selected as the least cost technically feasible technology for the **E METHUEN** injection location

Figure 24. Estimated total gross costs of possible NTA solutions for MWP based on varying levels of gross LCOE ($ millions per annum)

Mystic-Woburn Project	-20% Gross LCOE ($ millions)	Baseline Gross LCOE ($ millions)	+20% Gross LCOE ($ millions)
Pmax 15 MW	$184.6	$230.7	$276.8
Pmax 250 MW	$144.5	$180.6	$216.7
Pmax 750 MW	$177.1	$221.3	$265.6

In the Pmax 15 MW case, aeroderivative units are the technology of choice because of the smaller size requirements while a mix of CCGTs and aeroderivative units are selected frequently as the least cost technically feasible NTA technology under the Pmax 250 MW and Pmax 750 MW cases. Based on gross LCOE consideration, the Pmax 15 MW case is expected to be the most expensive case with a total gross cost in the range of $185 million to $277 million per year for a NTA solution in lieu of MWP. These gross costs are mainly driven by a relatively size of the installed capacity required to meet the reliability needs of MWP (713 MW for the Pmax 15 MW case versus 488 MW and 614 MW under the Pmax 250 MW and Pmax 750 MW cases, respectively). Despite a similar volume of CCGT capacity required under both cases (414 MW), the Pmax 750 MW features higher net direct cost than the Pmax 250 MW case due to a higher requirement of peaker aeroderivative (188 MW versus 62 MW for Pmax 250 MW).

It is worth noting that siting 475 MW of gas-fired generation over 8 different locations as suggested by Pmax 250 MW case (scenario 4) would be challenging in the Greater Boston area within the studied timeframe, given that so far there is only one known project in the interconnection queue that fits the technology (totaling 715 MW) and location (Boston area) – no additional projects have been announced for the Boston area at this time. Developing a new project would take significant time, which means that the timeline for solving reliability needs would likely not be met. Furthermore, the recent results of the FCA# 9[26] and the outlook for market conditions in the Greater Boston area do not indicate an express need for new CCGTs in the area in the short to medium term; therefore, it would be costly to bring such resources into the market given both the time constraints and the market's "demand" for new resources. In other words, based on LEI's analysis, it would be challenging to replace the MWP project by the solution featured in the Pmax 250 MW case. In addition to market conditions and commercial issues associated with siting and permitting such resources, the successful development of such resources would be limited by physical constraints such as land availability, gas pipeline infrastructure, cooling water availability and other factors, as discussed in Section 5.3.

5.2.2 Net direct cost estimates of NTA solutions for ratepayers

There is a big difference between current levels of SRECs ($245/MWh for 2017 forwards)[27] and the levels that such products could trade at over the economic life of the technology, for example from 2018 onward to 2038 and beyond. In 2020, for example, the Solar Carve-out program II expires.[28] It is reasonable to assume that toward the end of Solar Carve-out II (2020), as more solar units are added to the system, SREC prices are likely to converge toward current MA REC Class I prices.[29] Future REC prices for Class I may range from $0/MWh to the Alternative Compliance Payment ("ACP"), which is currently set at $67/MWh.[30] The reduction of cost provided to ratepayers by SREC revenues could vary a great deal based on market conditions and price levels. LEI captured this element of uncertainty in the scenario analysis as described in Section 5.2.2.

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[26] No CCGT unit cleared the FCA for the Boston area.

[27] Karbone Broker, February 17, 2015.

[28] The Solar Carve-out program II was launched in 2014 by the Massachusetts Governor with the target to install of 1.6 GW by 2020.

[29] Upon expiration of Solar carve-out II, new solar additions would be treated as conventional renewables.

[30] Source: Energy and Environmental Affairs of Massachusetts

Similarly LEI also considered the uncertainty of new generating resources such as CCGTs or peakers clearing the FCA. If all the resources in an NTA solution were to clear the FCA, that would reduce the clearing price in the FCA (and the capacity revenue offsets in the net LCOE), which would then raise the net direct costs of the NTA solution to ratepayers. Moreover, there may not be "room" in the near term auctions for additional resources to clear, as we have new resources – that would not be qualified to serve as part of an NTA solution for Greater Boston – already committed to the market. No CCGT units cleared the FCA #9 in the Greater Boston area and we do not anticipate such needs for the next few auctions. Consequently LEI calculated the net direct costs to ratepayers under two scenarios: (i) feasible resources would be able to clear FCAs in the long term yielding FCA payments (revenues) for only half (50%) of their life span; and (ii) feasible resources do not clear any FCA and consequently do not earn any capacity revenues to defray NTA direct costs to ratepayers. Figure 25 describes in details the four scenarios considered by LEI.

Figure 25. Summary of LEI's scenarios

Scenarios	Methodology	Key assumptions for net LCOE
Scenario 1 *(Gross LCOE net of High SRECs revenues and half FCM payments)*	**Net LCOE used to select the least cost technologies**	▪ We assume that by 2018-2020 solar resources will earn REC revenues at prices similar to 2017 SREC forwards ($321/kW-month) ▪ We assume that new resources such as CCGT and peakers would receive capacity payments for about half of their life cycle given the absence of need for such resources in the short to mid-term
Scenario 2 *(Gross LCOE net of high SRECs and no FCM payments)*	**Net LCOE used to select the least cost technologies**	▪ Same assumptions on SREC prices as Scenario 1 ▪ We assume no FCM revenues (no resources clear in the FCA)
Scenario 3 *(Gross LCOE net of Low SRECs revenues and no FCM payments)*	**Net LCOE used to select the least cost technologies**	▪ We assume that by 2018-2020 solar resources will earn REC revenues at prices similar to MA Class I REC ACP ($88/kW-month) ▪ We assume no FCM revenues (no resources clear in the FCA)
Scenario 4 *(Gross LCOE net of Low SRECs revenues and half FCM payments)*	**Net LCOE used to select the least cost technologies**	▪ We assume that by 2018-2020 solar resources will earn REC revenues at prices similar to MA Class I REC ACP ($88/kW-month) ▪ Same assumptions on FCM payments as Scenario 1

Figure 26. Summary of Net LCOE ($/kW-year) by technology

Feasible Technologies	Scenario 1 ($/kW-y)	Scenario 2 ($/kW-y)	Scenario 3 ($/kW-y)	Scenario 4 ($/kW-y)
CCGT	$ 57.2	$ 114.5	$ 114.5	$ 57.2
Peaker frame units	$ 44.0	$ 101.3	$ 101.3	$ 44.0
Peaker Aeroderivative	$ 148.3	$ 205.6	$ 205.6	$ 148.3
Dual fuel jet engine	$ 185.3	$ 242.6	$ 242.6	$ 185.3
Slow Discharge Batteries	$ 135.9	$ 135.9	$ 135.9	$ 135.9
Fast response Batteries	$ 121.2	$ 121.2	$ 121.2	$ 121.2
Solar Utility Scale (with storage)	$ 7.6	$ 27.6	$ 296.7	$ 276.7
Solar DG (with storage)	$ 133.3	$ 133.3	$ 402.5	$ 402.5
Passive DR (Energy Efficiency)	$ 247.5	$ 309.4	$ 309.4	$ 247.5
Active DR - Emergency Generation	$ 342.1	$ 370.8	$ 370.8	$ 342.1
Active DR - Real Time DR	$ 451.1	$ 479.8	$ 479.8	$ 451.1

In the Pmax 15 MW case, the least cost technology for all injection requirements is solar PV (with storage) under the high SREC value scenarios (with and without FCM revenues), while aeroderivative units are the technology of choice for scenarios involving low SREC values (with and without FCM revenues). In the Pmax 250 MW case and Pmax 750 MW cases, CCGTs are the technology of choice under all scenarios with aeroderivative units and Solar PV (with storage).

The total net direct cost (gross costs net of revenues offsets) for ratepayers was determined to range between $26 million and $147 million a year across the three NTA solutions (cases) and the range of technically feasible NTA technologies.[31] Although the lowest net direct costs to ratepayers materialize under the scenario 1, Pmax 250 MW case ($26.3 million a year) and Pmax 15 MW case ($30 million), such an outcome remains unlikely. In fact, leaving aside the physical difficulty of siting the large amount of solar required under scenario 1 (4.0 GW for Pmax 15 MW case for MWP) in the Greater Boston area, this very large requirement of solar-based technologies is likely to hinder the potential cost reduction ratepayers could get from SREC revenues. Under current SREC price levels, this NTA solution would be $76 million a year cheaper for ratepayers.[32] But such savings are rather unlikely as the implementation of the requested volume of solar units would likely flood the SREC market and likely depress SREC prices – even perhaps below the conservatively assumed REC ACP level under scenarios 3 & 4. As a consequence, the net direct cost to ratepayers will be higher. In other words, scenarios assuming low SREC prices (scenarios 3 and 4) are more likely to materialize than scenarios that assume current level of SREC prices is sustained in the long run (scenarios 1 and 2).

In addition, although it is not reasonable to assume that all generating plants clear the FCA given the outlook of market needs in the Greater Boston area, ruling out any FCM payments throughout the economic life of any of the new generating units is unrealistic. Although it is likely that a new generating resource that is an NTA would not likely clear next year's FCA, it is possible that some of the new plants clear later auctions and for this reason receive capacity payments for a portion of their economic life. For this reason, a scenario assuming a portion of capacity payments (scenario 4) is more likely than a scenario assuming no capacity payments (scenario 3). The least cost scenario was then determined based on comparison of net total cost across cases for the most probable scenario (scenario 4). Figure 27 summarizes the results of the analysis and illustrates each case on a bar chart. In addition, given uncertainties associated with underlying cost estimates, a further sensitivity was tested where the underlying gross LCOEs of the least cost, technically feasible NTA technologies in the solution under the Pmax 250 MW case were varied by + / - 20%. The baseline net direct costs to ratepayers for an NTA solution under scenario 4 was estimated to be $33 million a year.[33] The +/-20% range on the underlying gross LCOEs for an NTA solution to MWP produced a net direct cost to ratepayers in the range of $26 million to 39 million a year. Even in the -20% sensitivity case, the net direct cost to ratepayers exceeds MWP's annual revenue requirement of approximately $10 million a year.

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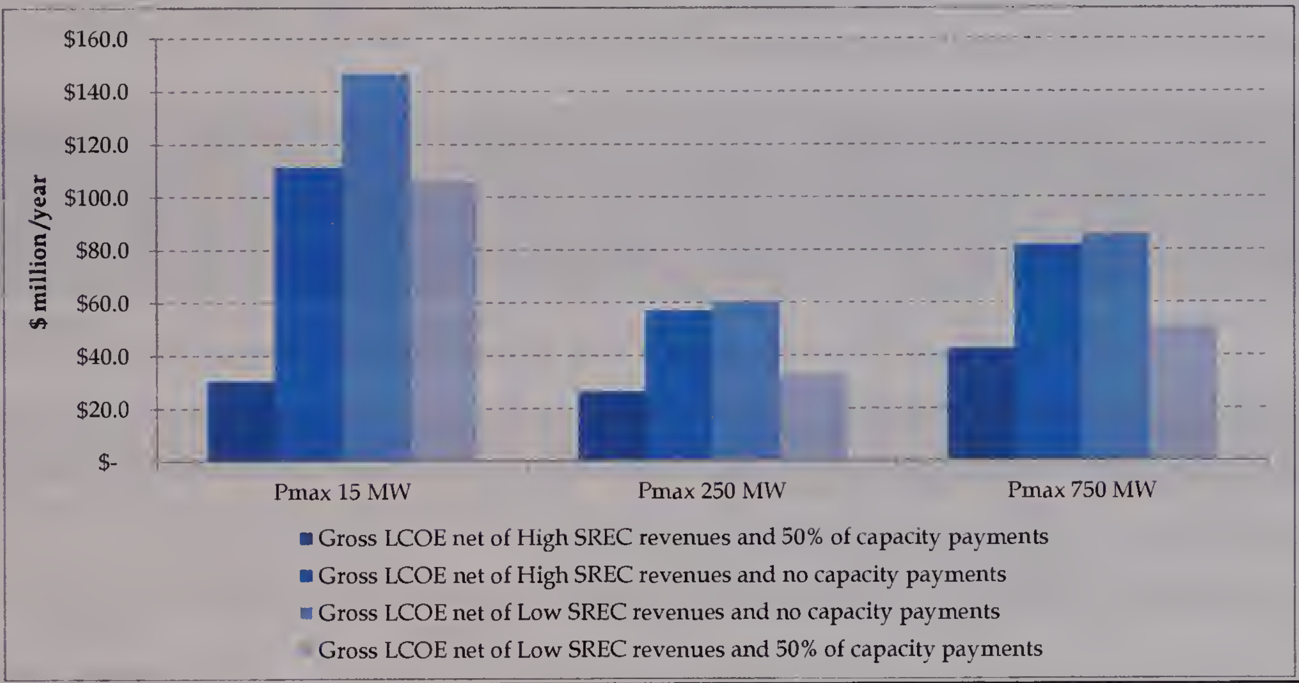
[31] Net LCOEs were derived from mid-range gross LCOE values.

[32] Maximum cost difference between Scenarios 1 and 4 across the three cases.

Figure 27. Estimated net direct costs of NTA solution for MWP per annum based on varying assumptions regarding offsetting revenues and subsidies



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[33] Furthermore, at the request of the utilities, LEI ran a sensitivity of the cost analysis assuming a capacity factor of 26% (instead of 15%) for solar PV. Although such assumption affects the net direct costs estimated under scenarios favorable to solar technologies, such assumption does not impact total net direct cost calculated for the case identified as the most probable for the reasons discussed in Section 5.2.2 (Pmax 250 MW case – scenario 4). In fact Pmax 250 MW case under scenario 4 does not require the installation of any solar-based technologies. In other words, the determined net direct cost of $33 million are not affected by changes in the assumptions on solar PV's average annual capacity factor. (See Appendix H for more details).

No Mystic - Woburn	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Scenarios	**Gross LCOE net of High SREC revenues and 50% of capacity payments**	**Gross LCOE net of High SREC revenues and no capacity payments**	**Gross LCOE net of Low SREC revenues and no capacity payments**	**Gross LCOE net of Low SREC revenues and 50% of capacity payments**
Pmax15 MW				
Total cost ($ million/ year)	$30.2	$111.3	$146.7	$105.8
Pmax 250 MW				
Total cost ($ million/year)	$26.3	$57.0	$60.0	$32.8
Pmax 750 MW				
Total cost ($ million/year)	$42.2	$81.6	$85.9	$51.5

Figure 28 provides an overview of the total capacity required at each location based on the characteristics of the least cost technically feasible NTA solution for each case and scenario. The purpose of this table is to demonstrate that both the mix of technologies and associated size requirements vary as we change the composition of technically feasible NTA technologies and the revenue assumptions underpinning the net LCOEs by technology.

Figure 28. Summary of MWs needed per scenario per case

	Mystic-Woburn Project							
	Hi SREC - 50% FCM		Hi SREC - NO FCM		Low SREC - NO FCM		Low SREC - 50% FCM	
Pmax = 15 MW	Solar Utility Scale (with storage)	4,042.7	Solar Utility Scale (with storage)	4,042.7	Peaker Aeroderivative	713.4	Peaker Aeroderivative	713.4
Pmax = 250 MW	Solar Utility Scale (with storage)	348.7	Solar Utility Scale (with storage)	348.7				
	CCGT	413.7	CCGT	413.7	CCGT	413.7	CCGT	413.7
					Peaker Aeroderivative	61.5	Peaker Aeroderivative	61.5
Pmax = 750 MW	Peaker Aeroderivative	100.2	Peaker Aeroderivative	100.2	Peaker Aeroderivative	187.5	Peaker Aeroderivative	187.5
	Solar Utility Scale (with storage)	494.7	Solar Utility Scale (with storage)	494.7				
	CCGT	413.7	CCGT	413.7	CCGT	413.7	CCGT	413.7

5.3 Qualitative discussion on feasibility of NTA solution in the Greater Boston area

There are several geographic considerations associated with each NTA technology that will have further bearing on its practical feasibility at a given hypothetical injection point. The scope of this analysis does not extend to identifying specific geographical features at each hypothetical injection point. Instead, this section comments on the general geographic requirements associated with each NTA technology and a macro-level assessment of feasibility in the Greater Boston region.

Some of the important geographical considerations are as follows:

Land requirements

Several NTA technologies, like utility scale solar generation (with storage) and CCGTs, require material site requirements in terms of buildable space (measured in acres) at or near the proposed hypothetical injection points in order to be a practically feasible solution. Specifically for utility scale solar generation (with storage), the proposed site must be fairly level, without shading from large buildings or other features and preferably should be free of vegetation (to reduce costs associated with clearing vegetation).

Under the Pmax 15 MW case across all scenarios, up to 4,043 MW of utility scale solar PV qualify as least cost feasible NTA technologies. In order to estimate the amount of land required to host this capacity of utility scale solar PV capacity, we assume that on average, one MW of utility scale solar PV requires 5 acres.[34] Therefore, in order to install 4,043 MW, approximately 20,213 acres of flat, unencumbered land in the Greater Boston region would be required. As a point of comparison, NREL has estimated that the total available land for utility-scale solar PV development in urban areas in the entire state of Massachusetts is limited to 56,400 acres.[35]

On the contrary, Pmax 250 MW case and Pmax 750 MW case require only up to 349 MW and 495 MW of utility scale solar units respectively. Although these relatively smaller amounts translate into fewer locations and smaller amounts of land (see figure below), it would still be challenging to get such a large magnitude of solar PV units commercially installed by 2018.

Figure 29. Feasibility of implementing utility scale solar generation for MWP

Mystic - Woburn Project	Pmax 15 MW Case	Pmax 250 MW Case	Pmax 750 MW Case
Total feasible least cost utility-scale solar PV (MW)	4,043	349	495
Total Land requirement (acres)	20,213	1,743	2,473

Enabling infrastructure

In addition to land, some NTA technologies also need other enabling infrastructure to be practically feasible at a given hypothetical injection point. For example, a CCGT or a peaking unit would require access to water (for cooling), as well as to fuel infrastructure (a CCGT and aeroderivative peaker taking gas would need access to gas pipeline facilities). Dual-fuel jet engines would also require a reliable supply of fuel oil (and permits to allow for oil storage on-site). Some CCGT or peaking units can be co-located alongside existing generation facilities (if there are sufficient resources) or on-site of retired generation or other former industrial facilities, which could reduce the costs of installation. However, only a handful of brownfield sites[36] are currently and presumably available.[37] Figure 30 summarizes the requirements for CCGTs across the Pmax 250 MW case and the Pmax 750 MW case under scenario 4. We estimated that 10 acres of land (spread across 8 locations) is required to site the amount of CCGT capacity needed under Pmax 250 MW and Pmax 750 MW cases respectively.

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[34] Based on plants of sizes ranging from greater than 1 MW to greater than 20 MW, Source: Land-Use Requirements for Solar Power Plants in the United, Stateshttp://www.nrel.gov/docs/fy13osti/56290.pdf

[35] NREL

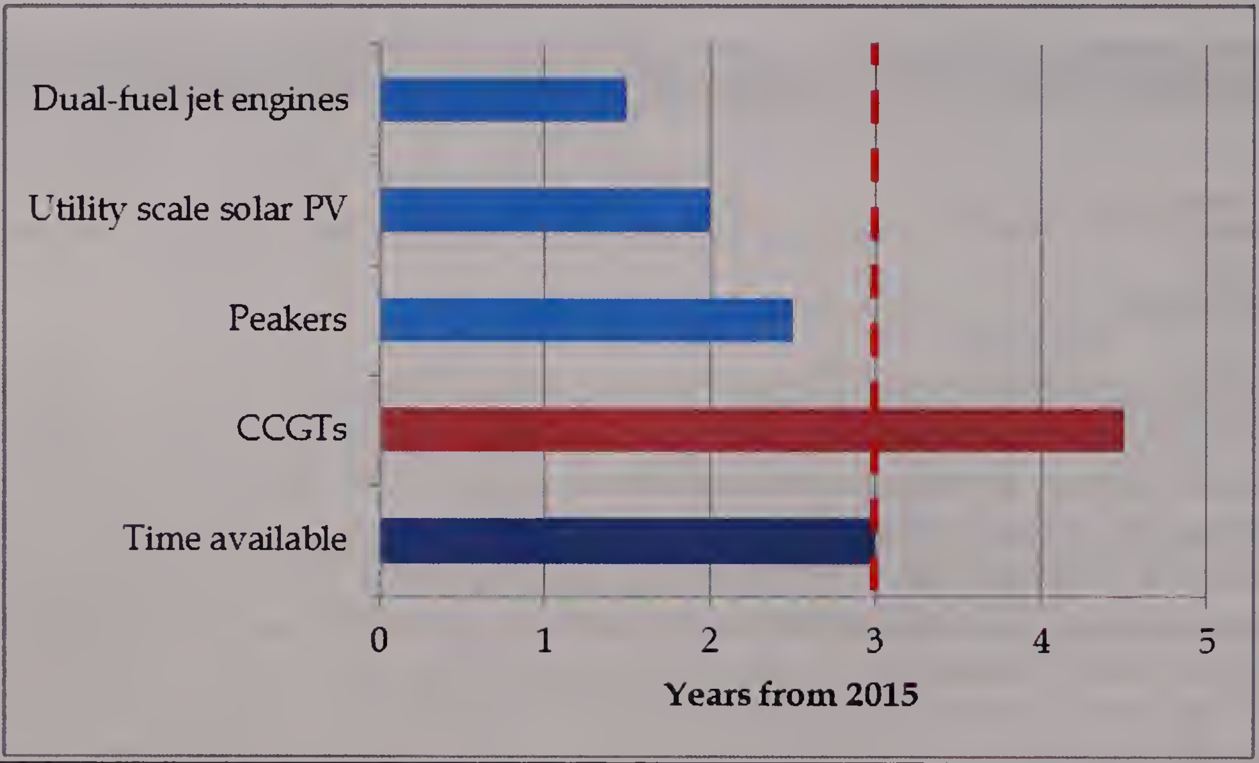
Figure 30. Summary of CCGT requirements for various MWP cases

Mystic - Woburn Project	Pmax 15 MW Case	Pmax 250 MW Case
Total feasible least cost CCGT (MW)	414	414
Total Land requirement (acres)	10	10

Implementation time

In addition to the land requirements and other enabling infrastructure needs for NTA technologies, it is also important to consider the time required to construct and bring online NTA technologies before the anticipated need in 2018. It is useful to consider the typical time involved for constructing (including pre-constructions processes such as permitting) the various NTA technologies relative to the 3 year time-frame available. As can be seen in Figure 31, a CCGT that starts its development process in 2015 will not be able to come online in time for the MWP requirements in 2018. The latest FCA results confirm that there are no new CCGTs slated to come online in the Greater Boston region by 2018.

Figure 31. Time required to bring online various NTAs relative to time available for MWP



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[36] We only considered facilities where gas-fired generating units were previously sited.

[37] Based on review of natural gas-fired plants currently retired in the Greater Boston area.

6 Conclusion

Although there are technically feasible NTA technologies that could meet the reliability needs of the system, they are estimated to be more costly than MWP. In fact, the most probable solution of technically feasible NTA technologies was estimated at a cost that is more than double MWP's expected annual revenue requirement (approximately $10million per year). Furthermore there are a host of practical and financial impediments in bringing about such NTA solutions in a relatively short period of time. Such practical hurdles include the siting challenge, identifying construction teams, acquiring land, procuring the equipment, and building out the requisite fuel supply infrastructure (as well as negotiating fuel supply contracts). From a planning perspective, the most probable alternative to MWP requires a total of 414 MW of additional new CCGT capacity and 62 MW of aeroderivative units spread over 8 different sites (in addition to what is currently planned to be built pursuant to ISO-NE's FCM, and above and beyond what is known publicly based on the current ISO-NE interconnection queue) by 2018 in the Boston area. The addition of such volume of gas-fired generation is difficult to envision mainly due to the absence of needs in the short to medium-term as illustrated by FCA#9's results, as well as to a number of other potential hurdles including constraints on construction time (commercialization by 2018), sufficiency of related infrastructure (including fuel supply-related infrastructure and water for cooling), as well as other permitting and siting challenges. As for the considered technologies, only a portion of the technologies analyzed and modeled were determined to be technically feasible from a planning perspective. Certain NTA technologies such as solar DG do not possess the operating characteristics required to meet the reliability needs under N-1 and N-1-1 contingencies and therefore could not provide the same reliability service as MWP. Although energy efficiency was considered a feasible NTA technology at some injection locations under the small sized NTA case, it also remains marginal contributor to the overall NTA solution, as it is often not viable at the necessary locations because of insufficient load.

7 Appendix A: LEI's Qualifications

London Economics International LLC ("LEI") is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation, transmission and distribution, with a suite of proprietary quantitative models to produce reliable and comprehensible results. The firm has its roots in advising on the initial round of privatization of electricity, gas, and water companies in the UK. Since then, LEI has advised private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, and strategy in virtually all deregulating markets worldwide.

LEI's areas of expertise straddle both the deregulated/market environments (including for example, price forecasting and asset valuation; wholesale power market analysis; market design (ISO market rules); and competitive procurement) and application of regulatory economics (such as regulated tariff design; cost of service ratemaking and performance based ratemaking; productivity analysis; policy design for incentivizing renewable energy and new technologies; and transmission and distribution network analysis). Provided below is a sample of previous LEI work showcasing its considerable experience, notably in the analysis of transmission projects and Non-Transmission Alternatives.

Sample of projects relating to Non-transmission alternatives, cost-benefit analysis of transmission projects

White paper on Non-transmission Alternatives (NTAs): London Economics International LLC ("LEI") was engaged by WIRES to prepare a White Paper on Market Resource Alternatives ("MRAs") which provides external parties with a clear understanding of MRAs and a concise description of how MRAs can work effectively alongside transmission investment in US power markets to support market development, reliability, and cost-effective supply. The structure of the White Paper specifically has the goal of "education" in mind. It started with the definition of MRAs, and then LEI presented case studies and lessons learned from several regional markets. The White Paper also recommended a conceptual analytical framework for proper and effective consideration of MRAs in transmission planning processes.

Cost-benefit analysis of a proposed transmission line: For a utility in the northeastern US, LEI prepared a cost-benefit analysis of a proposed transmission line with the potential to change existing market arrangements. In the analysis, LEI developed a base case and multiple project cases based on different configurations of the transmission project. Using its proprietary modeling tool, POOLMod, LEI simulated energy and capacity prices in each configuration over a 15-year timeframe, and compared the price differences against various cost allocation scenarios for the transmission line's construction. LEI also tested the statistical significance of the project case results against the base case results, and conducted further analysis on the economic effects of additional renewable generation projects that construction of the transmission line would make possible.

CHPE application for siting - Julia led LEI's team regarding the detailed cost-benefit analysis and macroeconomic impact analysis in support of the Champlain Hudson Power Express ("CHPE") application for siting approval at the New York Department of Public Service ("DPS"). LEI's analysis on economic effects was the cornerstone of the settlement agreement reached between Transmission Developers, Inc. ("TDI") and a number of New York agencies. Julia acted as independent expert on behalf of TDI and prepared updated study results on energy market impacts, capacity market impacts and also macroeconomic benefits stemming from the operation of the CHPE project. Julia's testimony was used in the DPS proceeding in the summer of 2012.

Lake Erie HVDC transmission project – cost /benefit analysis: LEI was hired by a private developer to assess the economics of the proposed Lake Erie HVDC transmission project and determining the additional revenue streams or value adders of the Lake Erie HVDC transmission project ("LEP") from the perspective of third-party shippers. The LEP is a 100-km long 1,000 MW bi-directional HVDC transmission line that will connect the Ontario energy market with the PJM market. LEI prepared a comprehensive report that includes a review of the Ontario and PJM markets, a 20-year (2017 to 2036) market outlook and prices for electricity, capacity and renewable energy credits in Ontario and the relevant zone/s in PJM; the total gross arbitrage value for the energy congestion rents, the capacity revenue potentials for PJM, and the renewable energy credits revenue potential in PJM.

Forecast the impact of a 1,000 MW DC transmission line on New England market prices: LEI prepared a 10-year energy market price outlook for the New England wholesale power market and forecast the impact of a proposed project on New England market prices. The project proposes to build a 1,000 MW DC-based transmission line that between Quebec and Vermont and import energy into Vermont. LEI modeled the long-term price forecast for Vermont and the rest of ISO-NE over the 2019-2028 period, and examined the price differentials. Two cases were modeled: a Base Case (without the HVDC project), and the Project Case (with the HVDC project). Analysis was done under the assumption that the transmission capacity on the project will accommodate low-cost hydro imports from Quebec. LEI also determined the benefits of the proposed transmission project on employment, economic activity, and tax revenues in New England. LEI utilized the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to Vermont and other New England states from the project on employment, economic activity, and tax revenues. LEI separated the economic impact caused by the construction of the project, and the impact caused by the reduction in energy prices due to the commercial operation of the project, taking into account issues such as usage of electricity in residential, commercial, and industrial sectors in the region, and also existing long-term energy contracts that would limit the impact of the project.

Assess the potential economic benefits of a New England transmission project: LEI was commissioned by Northeast Utilities to determine the potential economic benefits of the proposed NEEWS transmission project. Using detailed hourly simulation modeling of future power market conditions, LEI studied the potential market implications of NEEWS for ten years from a notional expected date of commercial operation of 2014. LEI reached the following conclusions: New England ratepayers could expect cumulative energy cost savings attributable to NEEWS over ten years under normal operating conditions; NEEWS would create regional energy market impacts; each phase of NEEWS would create energy market benefits over the ten-year modeling horizon; NEEWS would reduce LFRM costs each year; NEEWS would provide an insurance hedge against stressed system events; and NEEWS would offer market access to renewable resources in Northern New England/Canada.

Forecast the impact of a proposed transmission interconnection on Maine customers: LEI was engaged by a US power utility to perform a 15-year simulation analysis to estimate the market impacts resulting from a new transmission interconnection (covering the timeframe 2015-2029) and project the impact on Maine customers (including Northern Maine customers). LEI evaluated the market evolution with and without the interconnection and described the potential ramifications for purchasing electricity for Northern Maine customers. The analysis also estimated the potential impact on ratepayers from the re-allocation of the ISO-NE Pool Transmission Facility rate to incorporate the Northern Maine load and franchise area under a pro forma 10-year transitional agreement. LEI performed the modeling using our up-to-date ISO-NE simulation model (which covers the energy and capacity markets), extended to represent in detail the Maritimes control area.

Analysis of congestion rents and forecasted impact on energy and capacity prices due to a proposed transmission line: In connection with a proposed transmission line from Hydro Quebec to New York City, LEI Managing Director Julia Frayer led a team that forecasted 10-year energy and capacity prices of the New York market using POOLMod. The team also conducted analysis on congestion rents to support the client's negotiation with potential shippers. In support of the client's filing at the NYPSC, the LEI team conducted analyses on generation and production cost savings, emission reductions and sensitivities.

MA Energy Facilities Siting Board ("EFSB"): in response to NU retaining LEI, New England wholesale electricity markets were simulated in order to determine whether the Greater Springfield Reliability Project ("GSRP") would produce economic benefits to the New England region. In order to ensure that economic benefits were not subject to the forced outage and availability schedule of the simulated energy markets, LEI simulated the energy market with 30 different random forced outage and availability schedules. Using these simulations, a distribution of results was used to calculate confidence intervals and hypothesis tests run on the results, hence increasing the robustness of our findings. The study results introduced as testimony to the EFSB, which is scheduled to be presented in October. (2009) **[MA EFSB, EFSB 08-2/DPU 08-105/DPU 08-106]**

Assess the economic value of a proposed transmission project: LEI was hired by a transmission developer to conduct an independent rigorous modeling exercise to determine the potential revenues for the proposed transmission project wheeling power from western MISO to East MISO (and eventually PJM). LEI evaluated both the revenue opportunities to the investors (e.g., private benefits of the line based on market price differences and the market value of the transmission) as well as social benefits to the MISO system (i.e., wholesale price reductions and capacity market price differences); and evaluated the incremental value of the business strategy of selling the energy (and capacity) out of East MISO to third parties who will serve customers ultimately in PJM. LEI's modeling exercise entailed evaluating intrinsic revenues (originating from power markets), extrinsic revenue (originating from price volatility), along with the green value of the Project (originating from the purchase of low cost renewable energy). LEI's overall analysis was comprehensive and included a series of sensitivity scenarios testing key value drivers.

Sample of projects in New England

Projection of retail rates for commercial customers in New England: LEI performed a market study reviewing historical electric rates (and projecting forward electric rates) for large commercial customers in the New England market. The electric rates analysis was composed of a number of components, such as the commodity costs of electricity, compliance costs for certain state programs (like RPS), delivery charge for delivering electricity, and ancillary services and administrative supply charges. LEI created projections for each of these components and considered state retail sales requirements for renewables and other factors.

New England energy price outlook and economic impacts: LEI prepared a 10-year energy market price outlook for the New England wholesale power market and forecast the impact of a proposed transmission project on New England market prices. LEI also determined the benefits of the proposed transmission project on employment, economic activity, and tax revenues in New England. LEI utilized the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to various New England states from the project on employment, economic activity, and tax revenues. LEI took into account issues such as usage of electricity in residential, commercial, and industrial sectors in the region, and also existing long-term energy contracts that would limit the impact of the project.

Review of NESCOE study: LEI conducted a comprehensive review of the NESCOE Gas Electric Phase Three study in order to ensure that the appropriate economic models and techniques were being used to accurately model the hydro and gas solutions. LEI also aided the client in identifying any assumptions and modeling approaches which may be suboptimal, and communicated how these issues can be addressed and improved in future studies.

Connecticut

NU-NSTAR merger: in support of a client's opposition of a proposed NU-NSTAR merger, LEI analyzed the potential competitive market effects on a vertical scale and considered the extent of buyer market power for the purchase of standard service (full requirements) products. The testimony was submitted to the Public Utility Regulatory Authority (PURA). In a later submission, LEI also analyzed the settlements reached or proposed in a number of recent utility mergers. (2012) [PURA Docket No. 12-01-07]

CSC – NU/GSRP: LEI simulated the New England wholesale electricity markets in order to compare the economic benefits between Greater Springfield Reliability Project ("GSRP") and responses to the Connecticut Energy Advisory Boards' ("CEAB") RFP for a non-transmission alternative ("NTA") to GSRP. The NTA consisted of modeling a new CCGT plant to be placed in Southwestern Connecticut. In order to ensure that economic benefits were not subject to the forced outage and availability schedule of the simulated energy markets, LEI simulated the energy market with 30 different random forced outage and availability schedules. In effect these 30 different simulations added further robustness to our results because it captured the flexibility of the New England energy market under several different normal operating conditions. Furthermore the simulations created a distribution of results which was used to calculate confidence intervals and hypothesis tests, hence further increasing the robustness of our findings. The study results were used to produce written testimony to the CSC, oral testimony was provided in late August and early September 2009. (2008-2009) [CSC, Docket 370]

2006 "All Source" RFP: LEI served as the economic advisor to the Connecticut Department of Public Utility Control (DPUC), helping them design and implement an "all source" RFP for new capacity in the state in order to mitigate the exposure to ratepayers from Federally Mandated Congestion Costs. As economic advisor and RFP Coordinator, LEI was responsible for managing all aspects of the RFP, including design of innovative financial contracts for capacity, administration of RFP process, and evaluation of bids submitted by project sponsors, and recommendation to the DPUC for selection of winning projects. The selection of projects is based on a proprietary set of models that LEI staff designed to estimate the cost-benefit to ratepayers from long term contracts with new capacity, based on reduction in wholesale market costs across three different ISO New England power markets. LEI also submitted significant written testimony during the 18 months of this engagement, and LEI staff also testified orally on numerous occasions. (2006-2007) **[DPUC, Docket No. 05-07-14PH02; FERC, ER03-563-000]**

DPUC auction oversight: the DPUC retained the services of LEI to assist it in monitoring the power procurement processes for Connecticut Light & Power's (CL&P) Transitional Standard Offer auction in November 2004 for services in 2005 and 2006, and in September 2005 to monitor the November 2005 auction for services in 2006. LEI 's mandate included providing advisory services to the DPUC, including guidance on communications protocols, design of sales contract agreement (between CL&P and winning bidders), and also valuation of final bids vis-à-vis the forward market alternatives available to the utility. LEI filed affidavits after the completion of each auction process which the Commissioners used to approve the process and the contracts between CL&P and the winning bidders. (2004 and 2005) **[DPUC, Docket No. 03-07-18PH02]**

Maine

Advisory to Maine Public Utilities Commission on RPS: LEI presented a written report on the state of renewable portfolio standard (RPS) requirements in Maine and regionally across New England. LEI also testified at the Maine legislature. The report was commissioned by the Maine Public Utility Commission to fulfill a statutory requirement to provide research on the issue of RPS and its impact on generators and consumers.

Advisory to Maine Public Utilities Commission on transmission cost allocation: LEI advised Maine Public Utilities Commission on methodologies for transmission cost allocation by comparing and contrasting alternative planning approaches and pricing models employed within the US and one international jurisdiction, the United Kingdom. The final report will provide a 'strawman' recommendation for an effective cost allocation methodology. (2010) **[Docket No. RM10-23-000]**

Advisory to the Maine Public Utilities Commission on RFP: LEI assisted the Commission on the RFP related to the procurement of electricity in response to statutory mandates and state policy preferences. LEI provided economic analyses of bid proposals by estimating the benefits and costs to the ratepayers, and is currently supporting Commission staff in negotiations with short-listed bidders. (2009)

Development of an Electric Resource Adequacy Plan in Maine: in Docket No. 2008-104, LEI assisted the Maine Public Utilities Commission in developing an electric resource adequacy plan to aid MPUC in the development of a strategy for the pursuit of the long-term contracts. LEI submitted a report that builds up a set of recommendations for a long-term investment strategy based on an analysis of the current supply-demand situation, a review of the existing wholesale market rules for energy and the Forward Capacity Market, an examination of historical price trends, and review of the investment needs assessments prepared by the utilities and ISO-NE, as well as relevant sub-regional planning studies. (2008) **[Maine PUC, Docket No. 2008-104]**

Maine renewable portfolio requirement: LEI was engaged by the Maine Public Utilities Commission to conduct an in-depth analysis of the renewable portfolio standards ("RPS") required by a legislative Act. This analysis supported a Commission study and report to the Legislature. Julia led the team in preparation of the report, which was submitted to the Commission and later testified at the state legislature on the key findings of that report.

New Hampshire

Testimony describing wholesale market dynamics and benefits of Northern Pass in averting supply risks associated with generation "at risk" for retirement: On behalf of Public Service of New Hampshire, LEI testified in front of the new Hampshire Senate Committee on issue of eminent domain generally and more specifically, on the power market context and near term outlook for the New England power market and reasons for the development of a new proposed transmission project known as Northern Pass.

Vermont

Testimony on proposed merger between Central Vermont Public Service and Green Mountain Power: for a small independent power producer, LEI prepared a testimony on the potential harms of the proposed merger to the client and proposed certain conditions for the Vermont Public Service Board to consider. (2012) **[PSB Docket No. 7770]**

ISO-NE tariff design: LEI submitted testimony on behalf of ISO New England to the FERC to help defend ISO New England's self-funding tariff. LEI first defined the basic underlying economic principles for specifying the tariff, and then undertook to show how the tariff should be applied to various system users. The engagement involved an intensive financial modeling effort, and frequent interaction with stakeholders. (2000) **[ER01-316-000]**

Commercial litigation in New England

PPA contract dispute: LEI provided expert witness service for a private equity investor in matter related to a contractual dispute regarding a long term power purchase agreement between a municipal utility located in New England and a landfill gas generator. LEI analyzed the key contractual terms of the PPA and providing an expert's review of how those terms compared to the industry norm when the contract was signed and became effective. LEI will also be providing an independent estimate of potential contractual damages. (2010-2011) **[Commonwealth of Massachusetts Superior Court Department, Civil Action No. PLCV2006-00651-B]**

Updated market power analysis: prepared for a US utility's triennial review of market-based rate authorizations for certain subsidiaries in the northeast region. LEI analyzed the company's market power in PJM and ISO-NE. (2010) **[ER98-4159, et al.]**

Section 203 and 205 analysis in support of NRG's acquisition of certain Dynegy assets in CAISO and ISO-NE: LEI was engaged to provide testimony in support of a proposed acquisition. LEI performed a Delivered Price Test (DPT) for CAISO and ISO-NE energy markets as well as a standalone Herfindahl-Hirschman Index (HHI) analysis for the capacity markets. In addition, LEI discussed the impact of the acquisition of the ancillary services markets. (2010) **[EC10-88-000]**

Confidential FERC investigation in 2009-2010 of market manipulation in New England: Julia and her team assisted the client with certain matters pertaining FERC investigation. Specifically, the scope of this retention included economic and market analysis in support of a market participant in ISO New England's day ahead load response program ("DALRP"). Julia also provided affidavits and deposed in connection with FERC investigation of behind-the-fence industrial generator and participation in a wholesale power market in New England. Julia helped the client to respond to assertions of market manipulation and estimate market benefit provided through its participation in demand response program.

8 Appendix B: Technical and operational characteristics of various NTA technologies

Operating size and capacity factor

Each injection point has a specified amount of MW requirement that must be met by an eligible NTA. Each NTA under consideration has been selected based on whether previous examples of its successful operations have been documented in Massachusetts. In addition, the minimum and maximum operating size for the short-listed NTAs were determined by evaluating typical operating size of similar technologies in Massachusetts and where available in the Greater Boston region. In addition, each NTA also has a representative capacity factor which is based on actual data relevant to installations of that technology in Massachusetts and where available, in the Greater Boston region. Together these parameters help determine if a particular NTA can meet the injection requirements at a specific injection point.

Ability to respond to CLL requirements

One of the primary criteria to qualify as an N-1 NTA is the ability to operate whenever load in the Greater Boston region exceeds the critical load limit ("CLL"). According to the ISO New England, the CLL is defined as the load level at which a system problem could occur, and therefore a solution would be needed.[38] For MWP, the CLL has been estimated at 5,111 MW for peak load conditions in 2023. Figure 32 graphs this estimated CLL (red line) against the hourly load forecast for the Boston Zone in 2023 (blue band). As can be seen, the Boston Zone load does not exceed the CLL during most hours of the year (except for short periods in the summer, and rarely in winter). However, when looking at the maximum load during different times of the year, it is evident that in 2023, maximum summer load during the day and at night will exceed the CLL, which will cause system problems. In fact, in 2023, only the maximum load during night time in the shoulder months, and during winter day times will be less than the CLL

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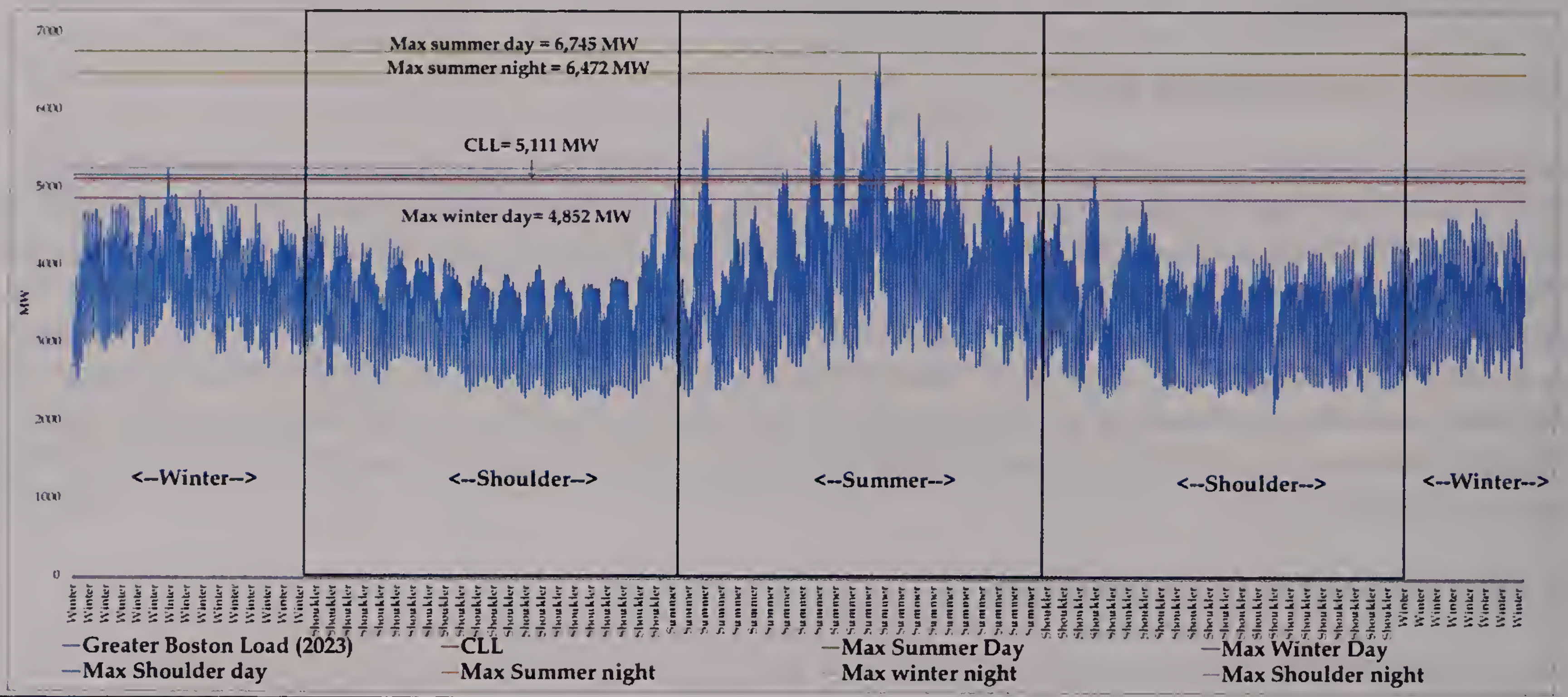
[38] Section 5.5: Information on Critical Load Level. Regional System Plan 2013. Available at: http://iso-ne.com/static-assets/documents/trans/rsp/2013/rsp13_final.docx

Figure 32. Forecast hourly load for Boston zone versus CLL for MWP



This implies that any technology that will qualify as a technically feasible NTA must be able to operate during the period where the Boston Zone load will exceed the CLL in 2023. This is essential because system problems caused when load exceeds the CLL can be reliably addressed only if the chosen NTA can operate during those periods. Figure 33 identifies which technology can operate in any of the six defined parts of a year. These parts of the year correspond to when load in the Greater Boston region varies during a typical year.

Figure 33. Seasonal characteristics of NTA technologies

	Summer	Winter	Shoulder	Summer	Winter	Shoulder
	Daytime	Daytime	Daytime	Nighttime	Nighttime	Nighttime
Combined Cycle Gas Turbine (CCGT)	1	1	1	1	1	1
Peaker Aeroderivative Unit	1	1	1	1	1	1
Peaker Frame Unit	1	1	0	0	0	0
Dual-fuel Jet Engine	1	1	1	1	1	1
Solar Utility Scale (with storage)	1	1	1	1	1	1
Solar Utility Scale	1	1	1	0	0	0
Solar DG (with storage)	1	1	1	1	1	1
Solar DG	1	1	1	0	0	0
Fast Discharge Battery	1	1	1	1	1	1
Slow Discharge Battery	1	1	1	1	1	1
Active DR - Emergency Generation	1	1	1	0	0	0
Active DR - Real Time DR	1	1	1	0	0	0
Passive DR (Energy Efficiency)	1	1	1	1	1	1

NTA can operate = 1; NTA cannot operate = 0

Source: LEI research

When comparing Figure 32 and Figure 33, it is clear that for MWP not all technologies can qualify as technically feasible NTAs.

Notes on the table

- In the case of CCGTs, it is assumed that newer units put in service as NTA technologies would be efficient enough so as to be economically committed for most hours and therefore available for any of the 6 previously defined parts of a year (summer, winter, shoulder/daytime and nighttime). Alternatively, if a CCGT is not in merit but needs to be committed to prevent an overload should an event occur, the ISO would have the option of committing the unit out-of-merit, albeit at a cost (which cost is not taken into account in our analysis)

- Peaker aeroderivatives and dual-fuel jet engines are small fuel-burning generator technologies which have the capacity of delivering power in a very short time frame even from a cold start. Their dual-fuel capability, make them also relatively flexible and less fuel constrained. It is therefore assumed that these units can be dispatched from a cold start following a contingency so as to provide the required level of injection and prevent an overload of a transmission component.

- In order for peaker frame units to operate as NTA technologies, they would need to be effectively committed and running when requested. These units would need to be committed and dispatched on a day-ahead basis, and secure fuel at least one day in advance. This lack of flexibility prevents these units to be available at night and during shoulder period (when the load is at lower levels).

- For obvious reasons, solar technologies (DG or utility-scale) without any kind of storage capacity are not eligible as NTAs as they cannot be dispatched should an event occur during the nighttime. However, coupled with a storage capacity sufficient to provide an energy output equivalent to their average capacity factor during all hours of the year, solar technologies become feasible as NTA technologies for all periods of the year.

- Batteries of both fast- and slow-discharge types are assumed available for all periods of the year as their charge status is not dependent on any particular time or period of the year.

- The use of emergency generation as a form of active DR is limited by federal, State/or local environmental air permits (because of toxic emissions) and is consequently limited in operational time (7 AM and 7 PM on all non-holiday weekdays)[39]. As a result, if cannot be considered as a technically feasible NTA events

- In addition to the seasonal characteristics of NTA technologies we also conducted a sensitivity analysis where energy efficiency is only available during day time hours. As can be expected, no energy efficiency qualifies as a technically feasible NTA under any of the three cases.

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[39] ISO-NE Operating Procedure No. 4 ("OP-4")

NTA Performance Parameters

Response time is an important criterion to determine eligible technologies under N-1 and N-1-1 contingency events. Under an N-1 contingency event, eligible NTAs must be able to inject power in less than 5 minutes. Under an N-1-1 contingency event, eligible NTAs must be able to inject power in less than 30 minutes. Some technologies, such as peakers and CCGTs can meet the N-1 response time requirements only if they are synchronized and ready to dispatch. However, if these technologies are ramping up from cold start, they cannot meet N-1 requirements, but can meet N-1-1 requirements depending on their ramp time. For example, a CCGT unit ramps up at the rate of 1.4% of its full rated capacity per minute. This would imply that in 30 minutes, a 100 MW CCGT unit will be able to inject 40.7 MW assuming at 95% capacity factor (1.4% * 100 MW * 30 minutes * 95%).

In addition to response time and ramp rate, the duration for which a given NTA can inject power after it has been called into service during a contingency event is also a vital criterion. Based on discussions with the Utilities, and LEI's understanding of ISO-NE rules,[40] LEI's model uses a conservative estimate of 12 hours as the minimum duration for which an NTA must remain online for either an N-1 or an N-1-1 contingency event in order to qualify as a technically feasible NTA.

Specific values for each of these criteria defined above are summarized in Figure 34. The second and third columns indicate the minimum and maximum MW size for each NTA. The column labeled ramp rates specifies how fast the corresponding NTA can ramp up to start producing at its maximum capacity. For example, a 14.3% of total size per minute ramp rate for Dual-fuel jet engines implies that these units can start producing at their maximum capacity in about 7 minutes. Finally, the last column, duration refers to the length of time these NTAs can produce power without interruption. For fossil fuel powered NTAs, the underlying assumption is that the availability of fuel is not a constraint. For NTAs with storage technologies such as solar PV, we assume that the storage capacity is long enough to support the NTA for during nighttime hours.

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[40] Subsection III of Part III – Procedure of ISO New England Operating Procedure No. 8 Operating Reserve and Regulation. May 2, 2014. Available at http://www.iso-ne.com/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

Figure 34. Technical characteristics of NTA technologies

NTA Resource	Installed Capacity range	Operations profile	Performance Rate	Duration (Hr.)
Combined Cycle Gas Turbine (CCGT)	100 to 800 MW range in MA	Baseload	95% availability factor	24
Peaker Aeroderivative Unit	1 to 125 MW range in MA	Peaking load	85% availability factor	24
Peaker Frame Unit	20 to 250 MW range in MA	Peaking load	83% availability factor	24
Dual-fuel Jet Engine	<1 to 50 MW	Peaking load	85% availability factor	24
Solar Utility Scale (with storage)	5 to 250 MW	Potential baseload depending on storage capacity	15% efficiency ratio	24
Solar Utility Scale	5 to 250 MW	Daytime peaking load during sunny days	15% efficiency ratio	12
Solar DG (with storage)	<1 to 5 MW	Potential peaking load depending on storage	15% efficiency ratio	12
Solar DG	<1 to 5 MW	Daytime peaking load during sunny days	15% efficiency ratio	8
Fast Discharge Battery	<1 to 10 MW	Can provide instantaneous power for short periods	Variable, depending on efficiency, charging time and storage capacity	2
Slow Discharge Battery	10 to 20 MW	Can provide steady supply of power for short periods	Variable, depending on efficiency, charging time and storage capacity	12
Active DR - Emergency Generation	Variable (based on type of equipment and load)	Peaking load	Assume 15% of peak load becomes available to respond	24
Passive DR (Energy Efficiency)	Variable (based on type of equipment and load)	Intermittent	Assume 15% of peak load becomes available to respond	24

Note 1: Maximum size of demand response (DR) depends on the amount of available load. We assume that the peak load at a given substation can be reduced by 15%
Note 2: Ramp rates for Peaker Aeroderivative units, Peaker frame units and dual-fuel jet engines sourced from: http://www.wartsila.com/fi/voimalat/learning-center/combustion-engine-vs-gas-turbine-ramp-rate
Note 3: Performance rates for CCGTs, Peaker Aeroderivative units, Peaker frame units and dual-fuel jet engines calculated based on the ISO New England EFORd Class Averages, sourced from: http://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf
Note 4: Maximum size for batteries can be significantly higher if individual batteries are connected together. LEI's analysis takes this possibility into account, and therefore the size represented here are not the exact values used for the analysis

Figure 35. Technology parameter determination assumptions

	Parameter	Methodology	Source
CCGT	**Minimum/Maximum Size**	Based on typical observed installed capacities, capped at the maximum value of CCGT unit in Massachusetts	Review of information provided by manufacturers (SIEMENS and GE) and actual data of operation in ISO-NE (based on new construction over the past 20 years)
	Ramp Rate	CCGTs are assumed already committed	Not applicable
	Performance Rate	CCGTs are assumed to have 95% availability factor	Based on ISO-NE EFORd Class Averages
	Duration	CCGTs are not energy limited resources	Not applicable
Peaker Frame Unit	**Minimum/Maximum Size**	Based on typical observed installed capacities	Review of information provided by manufacturers (SIEMENS and GE) and actual data of operation in ISO-NE
	Ramp Rate	Industry-standard ramp rates	Review of information provided by manufacturers and plants' operational data in ISO-NE
	Performance Rate	Peaker Aeroderivative units are assumed to have 85% availability factor	Based on ISO-NE EFORd Class Averages
	Duration	Frame units are not energy limited resources	Not applicable
Peaker Aeroderivative Unit	**Minimum/Maximum Size**	Based on typical observed installed capacities, with the assumption that several units can be installed together (capped at the value for which a peaker aeroderivative unit becomes a feasible technology	Review of information provided by manufacturers (SIEMENS and GE) and actual data of operation in ISO-NE (based on new construction over the past 20 years)
	Ramp Rate	Industry-standard ramp rates	Review of information provided by manufacturers and plants' operational data in ISO-NE
	Performance Rate	Peaker Frame units are assumed to have 83% availability factor	Based on ISO-NE EFORd Class Averages
	Duration	Aeroderivative units are not energy limited resources	Not applicable
Dual-Fuel Jet Engines	**Minimum/Maximum Size**	Based on typical observed installed capacities	Review of information provided by manufacturers (Wartsila) and actual data of operation in ISO-NE
	Ramp Rate	Industry-standard ramp rates	Review of information provided by manufacturers and plants' operational

	Parameter	Methodology	Source
			data in ISO-NE
	Performance factor	Dual fuel jet engines are assumed to have 85% availability factor	Based on ISO-NE EFORd Class Averages
	Duration	Jet Engines are not energy limited resources	Not applicable
Solar Utility-Scale	Minimum/Maximum Size	Based on typical observed installed capacities and ISO's definition	Review of utilities' new installations in MA and external sources such as "Utility-Scale Concentrating Solar Power and Photovoltaic Projects: A Technology and Market Overview." (National Renewable Energy Laboratory)
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Utility scale solar units have a conversion efficiency comparable to standard solar PV unit in MA	System Advisory Model ("SAM)" from National Renewable Energy Laboratory ("NREL") for Massachusetts
	Duration	Limited to daytime	Not applicable
Solar Utility-Scale with storage	Minimum/Maximum Size	Based on typical observed installed capacities and ISO's definition	Similar assumptions as for "utility scale solar"
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Utility scale solar units have a conversion efficiency comparable to standard solar PV unit in MA	System Advisory Model ("SAM)" from National Renewable Energy Laboratory ("NREL") for Massachusetts
	Duration	Storage capacity assumed sufficient to deliver energy equivalent to solar capacity factor at night [needed for a minimum of 12 hours to last through a contingency]	Not applicable
Solar DG	Minimum/Maximum Size	Based on typical observed installed capacities and ISO's definition	Review of utilities' new installations in MA and external sources such as "Utility-Scale Concentrating Solar Power and Photovoltaic Projects: A Technology and Market Overview." National Renewable Energy Laboratory. April 2012. http://www.nrel.gov/docs/fy12osti/51137.pdf
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Utility scale solar units have a conversion efficiency comparable to standard solar PV unit in MA	System Advisory Model ("SAM)" from National Renewable Energy Laboratory ("NREL") for Massachusetts

	Parameter	Methodology	Source
	Duration	Limited to daytime	Not applicable
Fast-Discharge Batteries	Minimum/Maximum Size	Based on typical observed installed capacities, with the assumption that batteries can be installed in banks (capped in the model to total installed capacity in the US in 2015)	Review of information provided by manufacturers (Flywheel (Beacon Power, Nas Batteries (NJK)) & Energy Storage Association
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Based on typical charging-discharging cycle efficiency	Review of information provided by manufacturers, and Electric Power Research Institute
	Duration	Typical value for available technologies	Review of information provided by manufacturers , and Electric Power Research Institute ("EPRI"),
Slow-Discharge Batteries	Minimum/Maximum Size	Based on typical observed installed capacities, with the assumption that batteries can be installed in banks (capped in the model to total installed capacity in the US in 2015)	Review of information provided by manufacturers (Flywheel (Beacon Power, sodium sulfur (NaS) Batteries (NJK)) & Energy Storage Association
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Based on typical charging-discharging cycle efficiency	Review of information provided by manufacturers, and Electric Power Research Institute
	Duration	Typical value for available technologies	Electric Power Research Institute ("EPRI")

9 Appendix C: Derivation of cost estimates for various NTA technologies

In this appendix we disclose gross and Net LCOE of all considered technologies (feasible and infeasible) and provide detailed information on all sources used. A summary of the sources utilized is documented in the following Figures.

Figure 36. Gross and net LCOE per technology ($/kW-year)

	CCGT	Frame Peaker	Aero Peaker	Dual Fuel Jet engine	Slow discharge batteries	Fast response energy storage	Utility-scale solar (with storage)	Soalr DG (with storage	Passive DR (EE)	Active DR (RTEG)	Active DR (RTDR)
Gross LCOE	397.8	231.2	323.4	362.9	181.4	154.3	458.2	523.3	424.2	371.0	480.0
Energy*	283.3	129.9	117.8	120.2	-	-	62.2	-	-	-	-
FCM	57.3	57.3	57.3	57.3	-	-	20.1	-	61.9	28.7	28.7
LFRM	-	-	-	-	12.5	-	-	-	-	-	-
Regulation	-	-	-	-	33.0	33.0	-	-	-	-	-
Avoided retailed cost	-	-	-	-	-	-	-	21.5	114.8	0.2	0.2
RECs (SRECs)	-	-	-	-	-	-	368.5	368.5	-	-	-
Net LCOE	57.2	44.0	148.3	185.3	135.9	121.2	7.4	133.3	247.5	342.1	451.1

Figure 37. Assumptions and sources on gross LCOE

Technologies	Methodology	Sources
Peaker (aeroderivative and frame units) and CCGT technologies	Gross LCOE based on ISO-NE's estimates adjusted for O&M and fuel cost	ISO New England's demand curve assumptions for the Forward Capacity Auction # 9 http://www.iso-ne.com/regulatory/ferc/filings/2014/apr/er14-1639-000_demand_curve_c
Energy storage (slow discharge and fast operating response)	Gross LCOE was estimated through LEI's proprietary LCOE model. Key inputs such as capital cost and VOM and FOM were sourced from NREL and PNNL. Results were then cross-checked against industry's estimates (IEA)	National Assessment of Energy Storage for Grid Balancing and Arbitrage", Pacific Northwest National Laboratory http://energyenvironment.pnnl.gov/pdf/National_Assessment_Storage_PHASE_II_vol_2_ International Energy Agency http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapEnergystorage.pdf and LEI Ice Energy, Ice Bear energy Storage system http://www.ice-energy.com/
Utility -scale solar	Gross LCOE was estimated through LEI's proprietary LCOE model. Key inputs to such as capital costs and O&M sourced from NREL, EIA and DOE. Results were then cross-checked against industry's estimates	National Renewable Energy Laboratory ("NREL") http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html Sun Shot Initiative (US Department of Energy), SEIA - http://www.seia.org/research-resources/solar-market-insight-report-2014-q1; and LEI
Solar DG	Gross LCOE was estimated through LEI's proprietary LCOE model. Key inputs to LEI's proprietary LCOE model such as capital costs and O&M provided by the Utilities. Results were then cross-checked against industry's estimates -(from NREL and DOE)	Utilities (National Grid and Eversource) (proprietary experience), NREL (PV system pricing trends, 2014 - http://www.nrel.gov/docs/fy14osti/62558.pdf and LEI
Dual fuel jet engine	Key inputs to LEI's proprietary LCOE model such as capital costs and O&M sourced from NYISO's estimates (technologies reviewed to established cost of new entry) sand Wärtsilä	Wärtsilä, NYISO Demand curves filing http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2013-08-22/2013%20NYISO%20Demand%20Curve%20Recommendation_draft_8-18-13.pdf

For market revenue information, we relied primarily on documents and market information made publicly available by ISO-NE and as relevant for the state of Massachusetts. For technical and cost information, sources relied upon include mainly independent engineering reports and market research performed by US government sponsored laboratories and research institutes as well as US Government agencies and manufacturing companies when relevant.

Figure 38. Assumptions and sources of revenue streams

Technologies	Methodology	Source
Energy	Determined average annual revenue on the energy markets for a generic technology based on LEI's outlook of market prices	Based on LEI's ISO-NE wholesale price forecasts
FCM	Revenues calculated based on FCA#9 results	Based on FCA#9 - http://www.iso-ne.com/markets-operations/markets/forward-capacity-market
LFRM	Revenues calculated using most recent clearing price (winter and summer) adjusted for participation time	Based on 2014 summer and winter results (net of capacity payments) http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2013/2013_amr_final_050614.pdf
Regulation	Revenue calculated based on regulation price adjusted for estimated market share	Based on 2013 clearing prices (ISO NE)
Avoided retailed cost	Avoided cost calculated based on average annual retail costs	EIA's statistics on MA's retail costs in MA; http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a
SREC prices	SREC revenues calculated based on forward curves	based on forward curves for SREC II (carveout II) for the year 2017 - source: Karbone and State of Massachusetts

10 Appendix D: Technically Feasible NTAs at substation level

Figure 39. Technically feasible NTA technologies for MWP (Pmax = 15 MW case)

Location (substation)	Requirement (MW)		Feasible NTA Technologies				
	N-1	N-1-1					
READING M139 115	0	2.4	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		
CHELSEA MA 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
MYSTIC GIS 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		
HAWKINS 516 115	0	2.3	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
HAWKINS 517 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
W AMESBURY 115	0	1.7	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
S DANVERS_54 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
S DANVERS_55 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
RAILYARD_45 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
RAILYARD_46 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
E BEVRLY 191 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
E BEVRLY 192 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
EVERETT 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
GOLDNHL45-58 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		
LYNN A179 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
MAPLEWOOD 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
NORTH RVR_54 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		
NORTH RVR_55 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		
RESCO-SAUGUS 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		Dual-fuel Jet Engine
REVERE 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
SALEM HARBOR 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
W SALEM_45 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
W SALEM_46 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
WATERS RV_54 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
WATERS RV_55 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
BARTHOLMW_45 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine

Location (substation)	Requirement (MW)		Feasible NTA Technologies				
	N-1	N-1-1					
BARTHOLMW_46 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
MELROSE 158 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
MELROSE 169 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
GE RIVER_179 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		Dual-fuel Jet Engine
GE RIVER_169 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		Dual-fuel Jet Engine
WAKEFLD JCT 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		
BEVERLY 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		Dual-fuel Jet Engine
LYNN Q169 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
GOLDNHL46-69 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		
SALEM HBR T4 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		
WAKEFLD145 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		
WAKEFIELD45 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		Dual-fuel Jet Engine
WAKEFLD146 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		
WAKEFIELD46 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		Dual-fuel Jet Engine
WATERS RIVER 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		
WAKEFLD_58 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		Dual-fuel Jet Engine
WAKEFLD_69 115	0	15	Slow Discharge Battery	Peaker Aeroderivative	Solar Utility Scale (with storage)		Dual-fuel Jet Engine

Figure 40. Feasible NTA technologies for MWP (Pmax = 250 MW case)

Location (substation)	Requirement (MW)		Feasible NTA Technologies					
	N-1	N-1-1						
WOBURN 345	0	16.4	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)		
READING M139 115	0	2.4	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)		
MYSTIC GIS 115	0	166.5		CCGT				
HAWKINS 517 115	0	6.1	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
W AMESBURY 345	0	1.7	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)		
REVERE 115	0	125.3	Slow Discharge Battery	CCGT				
GE RIVER_169 115	0	101.2	Slow Discharge Battery	CCGT	Peaker Aeroderivative			
SUDBURY 230	0	25.7	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)		

Figure 41. Feasible NTA technologies for MWP (Pmax = 750 MW case)

Location (substation)	Requirement (MW)		Feasible NTA Technologies					
	N-1	N-1-1						
WOBURN 345	0	16.4	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)		
WOBURN 115	0	2.5	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
READING M139 115	0	2.4	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)		
WATERTWN 520 115	0	42.6	Slow Discharge Battery		Peaker Aeroderivative			
WATERTWN 521 115	0	42.6	Slow Discharge Battery		Peaker Aeroderivative			
CHELSEA MA 115	0	10.2	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
MYSTIC GIS 115	0	166.5		CCGT				
HAWKINS 517 115	0	2.7	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)	Passive DR (Energy Efficiency)	Dual-fuel Jet Engine
W AMESBURY 345	0	14.3	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)		
REVERE 115	0	125.3	Slow Discharge Battery	CCGT				
GE RIVER_169 115	0	101.2	Slow Discharge Battery	CCGT	Peaker Aeroderivative			
SUDBURY 230	0	25.7	Slow Discharge Battery		Peaker Aeroderivative	Solar Utility Scale (with storage)		

11 Appendix E: Cost analysis results at substation level

In this appendix, we provided a detailed description of least cost feasible technology along with associated cost estimates across the five scenarios considered for each case (Pmax 15 MW case, Pmax 250 MW case and Pmax 750 MW case)

Figure 42. Pmax 15 MW case results summary

Mystic-Woburn Project Pmax = 15MW			Hi SREC - 50% FCM		Hi SREC - NO FCM		Low SREC - NO FCM		Low SREC - 50% FCM	
Substation Name	N-1	N-1-1	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies
Totals	0	606	$30		$111		$147		$106	
READING M139 115		2.4	$0.12	Solar Utility Scale (with storage)	$0.44	Solar Utility Scale (with storage)	$0.58	Peaker Aeroderivative	$0.42	Peaker Aeroderivative
CHELSEA MA 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
MYSTIC GIS 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
HAWKINS 516 115		2.3	$0.11	Solar Utility Scale (with storage)	$0.42	Solar Utility Scale (with storage)	$0.56	Peaker Aeroderivative	$0.40	Peaker Aeroderivative
HAWKINS 517 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
W AMESBURY 115		1.7	$0.08	Solar Utility Scale (with storage)	$0.31	Solar Utility Scale (with storage)	$0.41	Peaker Aeroderivative	$0.30	Peaker Aeroderivative
S DANVERS_54 115		15	$0.75	Solar Utility Scale (with	$2.75	Solar Utility Scale (with	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative

Mystic-Woburn Project Pmax = 15MW			Hi SREC - 50% FCM		Hi SREC - NO FCM		Low SREC - NO FCM		Low SREC - 50% FCM	
Substation Name	N-1	N-1-1	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies
				storage)		storage)				
S DANVERS_55 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
RAILYARD_45 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
RAILYARD_46 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
E BEVRLY 191 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
E BEVRLY 192 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
EVERETT 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
GOLDNHL45-58 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
LYNN A179 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
MAPLEWOOD 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative

Mystic-Woburn Project Pmax = 15MW			Hi SREC - 50% FCM		Hi SREC - NO FCM		Low SREC - NO FCM		Low SREC - 50% FCM	
Substation Name	N-1	N-1-1	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies
NORTH RVR_54 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
NORTH RVR_55 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
RESCO-SAUGUS 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
REVERE 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
SALEM HARBOR 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
W SALEM_45 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
W SALEM_46 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
WATERS RV_54 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
WATERS RV_55 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
BARTHOLMW_45 115		15	$0.75	Solar Utility Scale	$2.75	Solar Utility Scale	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative

Mystic-Woburn Project Pmax = 15MW			Hi SREC - 50% FCM		Hi SREC - NO FCM		Low SREC - NO FCM		Low SREC - 50% FCM	
Substation Name	N-1	N-1-1	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies
				(with storage)		(with storage)				
BARTHOLMW_46 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
MELROSE 158 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
MELROSE 169 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
GE RIVER_179 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
GE RIVER_169 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
WAKEFLD JCT 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
BEVERLY 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
LYNN Q169 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
GOLDNHL46-69 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative

Mystic-Woburn Project Pmax = 15MW			Hi SREC - 50% FCM		Hi SREC - NO FCM		Low SREC - NO FCM		Low SREC - 50% FCM	
Substation Name	N-1	N-1-1	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies
SALEM HBR T4 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
WAKEFLD145 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
WAKEFIELD45 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
WAKEFLD146 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
WAKEFIELD46 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
WATERS RIVER 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
WAKEFLD_58 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative
WAKEFLD_69 115		15	$0.75	Solar Utility Scale (with storage)	$2.75	Solar Utility Scale (with storage)	$3.63	Peaker Aeroderivative	$2.62	Peaker Aeroderivative

Figure 43. Pmax 250 MW case results summary

Mystic-Woburn Project Pmax = 250MW			Hi SREC - 50% FCM		Hi SREC - NO FCM		Low SREC - NO FCM		Low SREC - 50% FCM	
Substation Name	N-1	N-1-1	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies
Totals	**0**	**445.3**	**$26.26**		**$56.95**		**$60.01**		**$32.78**	
WOBURN 345		16.4	$0.82	Solar Utility Scale (with storage)	$3.01	Solar Utility Scale (with storage)	$3.97	Peaker Aeroderivative	$2.86	Peaker Aeroderivative
READING M139 115		2.4	$0.12	Solar Utility Scale (with storage)	$0.44	Solar Utility Scale (with storage)	$0.58	Peaker Aeroderivative	$0.42	Peaker Aeroderivative
MYSTIC GIS 115		166.5	$10.02	CCGT	$20.06	CCGT	$20.06	CCGT	$10.02	CCGT
HAWKINS 517 115		6.1	$0.30	Solar Utility Scale (with storage)	$1.12	Solar Utility Scale (with storage)	$1.48	Peaker Aeroderivative	$1.06	Peaker Aeroderivative
W AMESBURY 345		1.7	$0.08	Solar Utility Scale (with storage)	$0.31	Solar Utility Scale (with storage)	$0.41	Peaker Aeroderivative	$0.30	Peaker Aeroderivative
REVERE 115		125.3	$7.54	CCGT	$15.10	CCGT	$15.10	CCGT	$7.54	CCGT
GE RIVER_169 115		101.2	$6.09	CCGT	$12.20	CCGT	$12.20	CCGT	$6.09	CCGT
SUDBURY 230		25.7	$1.28	Solar Utility Scale (with storage)	$4.72	Solar Utility Scale (with storage)	$6.22	Peaker Aeroderivative	$4.48	Peaker Aeroderivative

Figure 44. Pmax 750 MW case results summary

Mystic-Woburn Project Pmax = 750MW			Hi SREC - 50% FCM		Hi SREC - NO FCM		Low SREC - NO FCM		Low SREC - 50% FCM	
Substation Name	N-1	N-1-1	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies	Least cost solution (M$/year)	Least cost feasible technologies
Totals	0	552.4	$42.21		$81.58		$85.91		$51.46	
WOBURN 345		16.4	$0.82	Solar Utility Scale (with storage)	$3.01	Solar Utility Scale (with storage)	$3.97	Peaker Aeroderivative	$2.86	Peaker Aeroderivative
WOBURN 115		2.5	$0.12	Solar Utility Scale (with storage)	$0.46	Solar Utility Scale (with storage)	$0.60	Peaker Aeroderivative	$0.44	Peaker Aeroderivative
READING M139 115		2.4	$0.12	Solar Utility Scale (with storage)	$0.44	Solar Utility Scale (with storage)	$0.58	Peaker Aeroderivative	$0.42	Peaker Aeroderivative
WATERTWN 520 115		42.6	$7.43	Peaker Aeroderivative	$10.30	Peaker Aeroderivative	$10.30	Peaker Aeroderivative	$7.43	Peaker Aeroderivative
WATERTWN 521 115		42.6	$7.43	Peaker Aeroderivative	$10.30	Peaker Aeroderivative	$10.30	Peaker Aeroderivative	$7.43	Peaker Aeroderivative
CHELSEA MA 115		10.2	$0.51	Solar Utility Scale (with storage)	$1.87	Solar Utility Scale (with storage)	$2.47	Peaker Aeroderivative	$1.78	Peaker Aeroderivative
MYSTIC GIS 115		166.5	$10.02	CCGT	$20.06	CCGT	$20.06	CCGT	$10.02	CCGT
HAWKINS 517 115		2.7	$0.13	Solar Utility Scale (with storage)	$0.50	Solar Utility Scale (with storage)	$0.65	Peaker Aeroderivative	$0.47	Peaker Aeroderivative
W AMESBURY 345		14.3	$0.71	Solar Utility Scale (with storage)	$2.62	Solar Utility Scale (with storage)	$3.46	Peaker Aeroderivative	$2.49	Peaker Aeroderivative
REVERE 115		125.3	$7.54	CCGT	$15.10	CCGT	$15.10	CCGT	$7.54	CCGT
GE RIVER_169 115		101.2	$6.09	CCGT	$12.20	CCGT	$12.20	CCGT	$6.09	CCGT
SUDBURY 230		25.7	$1.28	Solar Utility Scale (with storage)	$4.72	Solar Utility Scale (with storage)	$6.22	Peaker Aeroderivative	$4.48	Peaker Aeroderivative

12 Appendix F: Summary of the Non-Transmission Alternative Reliability Planning Analysis

12.1 Analysis Description

A Non-Transmission Alternative (NTA) solution reliability assessment study was conducted to determine the resource requirements needed to address thermal overloads in the Greater Boston study area assuming specific proposed transmission projects were to be deferred. The assessment considered the reliability needs for the projected 2023 transmission system serving the Greater Boston study area under N-1 and N-1-1 contingency conditions. The analysis was designed to identify the specific size of resources and their specific locations within the transmission system that would be needed to mitigate transmission overloads seen on the 2023 transmission system absent certain transmission upgrades. However, the NTA resources would need to be in service by the same date that these certain transmission upgrades are expected to be in service as identified in the ISO-NE Regional System Plan (2017-2018).

12.2 Modeling Assumptions

A subset of the set of base cases used in the Greater Boston Solution Study was selected for use in the NTA analysis. Selection of the base cases was based on a worst-case contingency overload assessment. This assessment was based on high level testing of all N-1-1 contingencies applied to the entire set of Greater Boston cases without the excluded upgrade. The results of this testing were reviewed to determine the worst performing cases in terms of the number and magnitude of thermal overloads observed. One worst case was then selected from the set of cases with two generating units unavailable and a second worst-case was selected from the set of cases with one generating unit unavailable. These selected cases were then used for further testing with the system upgrade excluded in the more detailed full analysis to determine the amount and location of NTA resources needed.

The assumptions concerning eligible locations for NTA resources considered the voltage level of numerous points of the transmission system. The smallest sized resources were placed at only 115-kV nodes as their application at higher voltage nodes was considered impractical particularly in light of the fact that all 115-kV nodes are directly or indirectly connected to higher voltage nodes and placements at the higher voltage nodes would be redundant. Conversely the middle size and large size resources were placed at 115-, 230-, and 345-kV nodes as it was recognized that the optimization process would not dispatch resources to levels that created additional overloads and, as such, only the amount of resources that could practically be added to a node, in terms of thermal constraints, would be dispatched.

The resources used in the dispatch optimization analysis were modeled at three different maximum sizes (P_{max}) as a means to model different categories of resource types. The small size (representative of resources such as PV or small wind units) had a maximum dispatch of 15 MW at each node, and 159 nodes were eligible for dispatch. The middle size had a maximum dispatch of 250 MW and was modeled at 180 nodes (representative of medium sized generating units). Finally, a large resource size was modeled which had a maximum dispatch of 750 MW across 180 nodes (representative of a large generating plant addition).

12.3 Analytical Process

The analysis used a subset of the same set of transmission system base case models used for the Greater Boston Solution study as well as the same analytical tool used in that study. These models include ISO-NE's forecast[41] of the 2023 90/10 summer peak demands and energy efficiency as well as existing passive and active demand resources as established through Forward Capacity Auction No. 7. This analytical tool permitted modeling of operating adjustments for the Boston area phase shifters (located at the Waltham and Baker St. Substations) as well as adjustment of fast start resources in the Greater Boston area. Additionally, modeling of operation of HVDC resources (such as the Sandy Pond HVDC terminal) was included.

The analytical tool also has the capability to optimize the dispatch of a multitude of generating resources across a defined area as a means to mitigate transmission overloads that are the consequence of single contingency (N-1) or multiple contingency (N-1-1) events. The analytical tool can also optimize settings for phase shifters and HVDC terminals to aid in the optimization of resources needed to mitigate overloads. These adjustments are consistent with the adjustments system operators use in anticipation of contingencies and in response to overloads before, after or between contingency events.

The analytical tool performs a power-flow analysis on the base system model for each N-1 contingency and then determines the amount of resource, up to a defined maximum, that is needed at each of the defined "nodes" on the transmission system where resources may be connected either directly or downstream from points on the modeled transmission system. The first step in the NTA analysis process was placement of "study" units (i.e., potential resource additions) at a large number of nodes on the Greater Boston transmission system. This created a large set of theoretical resource locations. The size of these resources was allowed to range between 0 and a defined maximum value; three specific maximums were used in order to examine the difference in required resources. This was followed by a contingency analysis step where all overloads were identified for all contingency events that were modeled. The contingency analysis considers all overloads that occur for the entire set of N-1 modeled contingency events and determines the minimum amount and optimal location of resource dispatch needed to address these overloads. These resources would be dispatched either before or immediately after the N-1 event. The results of this analysis determined those resources needed for N-1 events, and these resources were modeled as available and running in subsequent testing. Once the N-1 dispatch had been established the process was repeated modeling initial contingency events followed by a second contingency (N-1-1) event. Following each initial contingency event additional resource dispatch optimization adjustments are made in order to address all overloads seen as a result of the entire set of modeled second contingency events. The final step in the process was a mathematical analysis that selected the optimal nodes and output levels from the set of available "study" resources as a means to mitigate all identified overloads for N-1-1 events. This optimization process attempted to place the least amount of potential resource (up to 15 MW for the small resource case, up to 250 MW for the middle resource case and up to 750 MW for the large resource case) at the most effective locations needed to mitigate all overloads found to exist for each of the modeled conditions. This resource dispatch in combination with phase shifter adjustments is consistent with the adjustments operators could potentially make between contingency events when addressing N-1-1 transmission overloads.

---

[41] The ISO-NE forecast used in the study was based on the 2013 CELT report.

12.4 Results

The results shown in Table 1 below include identification of the total number of locations and total amount of NTA resources needed to address N-1 overloads followed by NTA resources needed to address N-1-1 overloads incrementally. The results shown include results for the two base cases (i.e. one two-unit out case and one one-unit out case) associated with the excluded upgrade identifying the number of locations and the maximum dispatch level needed to address all associated overloads for both cases under N-1 and N-1-1 conditions.

The optimization process attempts to identify the least amount of resource needed to address identified overloads. The analysis first finds a helpful location to place a resource and then continues to increase the dispatch level until either the maximum level is reached or additional increases are no longer helpful. The analysis then proceeds to the next most helpful location and continues with the process until either all overloads are mitigated and/or all possible helpful locations have been utilized. The cases with larger dispatch levels may result in selection of fewer locations. However, the level of dispatch that is helpful may be limited by a number of factors such as introduction of new overloads or possibly making existing overloads more severe. Consequently, as seen in the 250 MW case versus the 750 MW case we may find that there is little difference in the final selected set of locations and dispatch levels needed.

Figure 45. Summary of Total NTA MW Resource and Number of NTA Locations Needed

Upgrade Excluded	**Mystic - Woburn Project (MWP)**					
P_{max} Level	**15MW**		**250MW**		**750MW**	
Contingency Level	**N-1**	**N-1-1**	**N-1**	**N-1-1**	**N-1**	**N-1-1**
Total NTA Resource Needed (MW)	0.0	606.4	0.0	445.3	0.0	552.4
Total Number of Injection Points	0	43	0	8	0	12

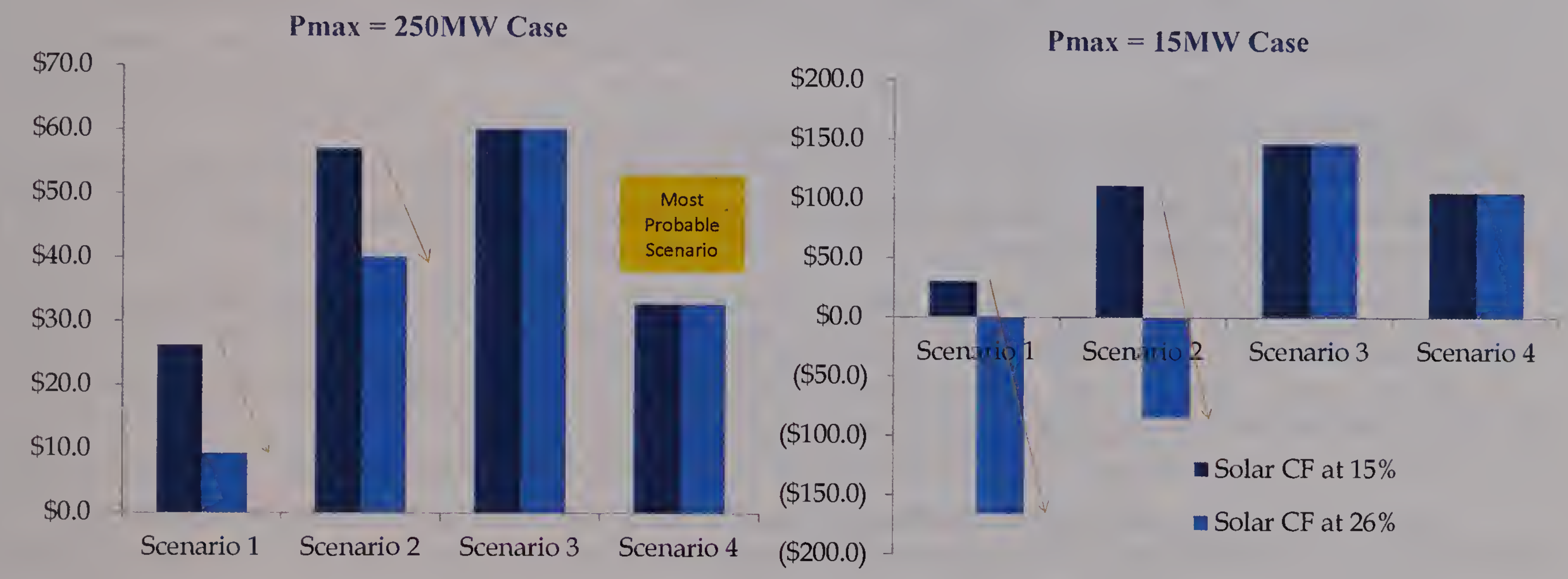
12.5 Modeling Tool Description

The PowerGEM Transmission Analysis and Reliability Assessment (TARA) application version 7.10 was used to conduct all thermal contingency and resource optimization analysis presented in this report. TARA is a power flow software tool used for identifying and analyzing transmission bottlenecks, DC (linear) & AC (non-linear) contingency analysis, Security Constrained Economic Dispatch (SCED), and Security Constrained Reliability Dispatch (SCRD). Use of this application allowed for optimization of phase shifter settings and generator dispatch needed to mitigate overloads and provided results that are representative of operational responses to such overloads. The application has the capability of processing multiple base cases against a large number of contingencies and generates output that fully summarizes the results of the analysis.

13 Appendix G: Sensitivity cost analysis on solar PV capacity factor

At the request of the utilities, LEI ran a sensitivity of the cost analysis assuming a capacity factor of 26% (instead of 15%) for solar PV. Although such assumption affects the net direct costs estimated under scenarios favorable to solar technologies, as illustrated by Figure 46, such assumption does not impact total net direct cost calculated for the case identified as the most probable for the reasons discussed in Section 5.2.2 (Pmax = 250 MW case– scenario 4). The net direct cost generates under Pmax = 250 MW case remained unchanged due to the absence of requirements for solar based technologies. It bears noting, however, that a higher capacity factor for solar decreases net direct cost under scenarios 1 and 2 (which are favorable to solar technologies given assumptions on high SREC prices) by 75% and 30% respectively. In extreme case scenarios such as Pmax = 15 MW case (requiring 4.0 GW of solar based technologies under scenarios 1 and 2), higher capacity factor for solar could potentially result in virtually no cost for the ratepayers (see negative net direct cost on the charts) as the solar based technologies would be able to achieve self-sufficiency on the market (pending favorable SREC price conditions). As previously discussed such scenarios are the least probable ones.

Figure 46. Illustration of the impact of a higher solar capacity factor on estimates net direct cost



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APPENDIX 6-1

Electric and Magnetic Field (EMF) Analysis for the Mystic to Woburn 211-514x and 211-514y 115 kV Transmission Lines

(March 6, 2015)

Electric and Magnetic Field (EMF) Analysis for the Mystic-to-Woburn 211-514x and 211-514y, 115-kV Transmission Lines

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1 Introduction and Summary

NSTAR Electric Company *d/b/a* Eversource Energy ("Eversource"), has proposed to supplement an existing HPFF 115-kV line (211-514x) by installing a new HPFF 115-kV line (211-514y) parallel to this line along the existing line route from Mystic Substation in Everett, MA to Woburn Substation in Woburn, MA. Both the existing and proposed lines are underground.

Eversource requested that Gradient perform an independent assessment of the electric and magnetic field (EMF) impacts associated with the planned project. We conservatively modeled EMF using peak 2018 projected line loadings provided by Eversource for two scenarios: one with the proposed line included, and one with the existing line only (Velez, 2015).

As described in this report, we found that magnetic field levels calculated to exist above the underground cables are well below the International Commission on Non-Ionizing Radiation Protection (ICNIRP) health-based guidelines for public exposure to EMF (2,000 mG). In addition, all field values are below the Massachusetts ROW-edge magnetic field guideline value of 85 mG (MAEFSB, 2010). Since underground lines produce no aboveground electric fields and all proposed lines associated with the substation are underground, there will be no aboveground post-project electric fields.

We found that the maximum magnetic field value generated by the combined effects of the two lines at peak operation load is 3.61 mG. It is located above the centerline of the proposed 115-kV line. In all models, field values decrease rapidly with lateral distance from the lines. The maximum magnetic field value generated at peak operation load in the scenario where no new line is installed is 4.10 mG.

In this report, Section 2 describes the nature of EMF and provides values for EMF levels both from common sources and from available EMF exposure guidelines. Section 3 outlines the EMF modeling procedures for calculating magnetic field strengths as a function of lateral distance from an electric transmission or distribution line, as well as providing graphical and tabular results. Section 4 summarizes the conclusions, and Section 5 lists the bibliographic references.

2 Nature of Electric and Magnetic Fields

All matter contains electrically charged particles. Most objects are electrically neutral because positive and negative charges are present in equal numbers. When the balance of electric charges is altered, we experience electrical effects, such as the static electricity attraction between a comb and our hair, or drawing sparks after walking on a synthetic rug in the wintertime. Electrical effects occur both in nature and through our society's use of electric power (generation, transmission, consumption).

2.1 Units for EMF Are Kilovolts per Meter (kV/m) and Milligauss (mG)

The electrical tension on utility power lines is expressed in volts or kilovolts (kV; 1 kV = 1,000 V). Voltage is the "pressure" of the electricity, and can be envisioned as analogous to the pressure of water in a plumbing system. The existence of a voltage difference between power lines and ground results in an "electric field," usually expressed in units of kilovolts per meter (kV/m). The size of the electric field depends on the voltage, the separation between lines and ground, and other factors.

Power lines also carry an electric current that creates a "magnetic field." The units for electric current are amperes (A) and are a measure of the "flow" of electricity. Electric current can be envisioned as analogous to the flow of water in a plumbing system. The magnetic field produced by an electric current is usually expressed in units of gauss (G) or milligauss (mG), where 1 G = 1,000 mG. Another unit for magnetic field levels is the microtesla (μT), where 1 μT = 10 mG. The size of the magnetic field depends on the electric current, the distance to the current-carrying conductor, and other factors.

2.2 There Are Many Natural and Man-made Sources of EMF

Everyone experiences a variety of natural and man-made electric and magnetic fields. Electric and magnetic field levels can be slowly varying or steady (often called "DC fields"), or can vary in time (often called "AC fields"). When the time variation of interest corresponds to that of power line currents, *i.e.*, 60 cycles per second, the fields are called "60-Hz" EMF. Man-made magnetic fields are common in everyday life. For example, many childhood toys contain magnets. Such permanent magnets generate strong, steady magnetic fields. Typical toy magnets (*e.g.*, "refrigerator door" magnets) have fields of 100,000 to 500,000 mG. On a larger scale, the earth's core creates a steady magnetic field that can be easily demonstrated with a compass needle. The size of the earth's magnetic field in the northern US is about 550 mG (over a hundred times smaller than fields generated by "refrigerator door" magnets). Knowing the strength of the earth's magnetic field provides a perspective on the size of power line magnetic fields. The earth's steady field does not have the 60-Hz time variation characteristic of power line EMF, but is experienced as a changing magnetic field as one moves around in it. Alternatively, moving magnets generate time-varying magnetic fields. For example, a magnet spinning at 60 times a second will produce a 60-Hz magnetic field indistinguishable from that found near electric power lines carrying the appropriate level of electric current. Even the rotating steel-belted radial tires on a car produce time-varying magnetic fields. And although magnetic resonance imaging (MRI) is a diagnostic procedure that puts humans in much larger, but steady, magnetic fields (*e.g.*, 20,000,000 mG), it is preferred over taking an X-ray picture. Contrary to X-rays, MRIs have no known health risks (other than the large forces exerted on nearby steel objects).

2.3 Power-frequency EMF Are Found Near Electric Lines and Appliances

Electric power transmission lines, distribution lines, and electric wiring in buildings carry AC currents and voltages that change size and direction at a frequency of 60 Hz. These 60-Hz currents and voltages create 60-Hz EMF nearby. The size of the magnetic field is proportional to the line current, and the size of the electric field is proportional to the line voltage. The EMF associated with electrical wires and electrical equipment decrease rapidly with increasing distance away from the electrical wires.

When EMF derives from different sources (*e.g.*, adjacent wires), the size of the net EMF produced will be somewhere in the range between the sum of EMF from the individual sources and the difference of the EMF from the individual sources. Thus, EMF may partially add, or partially cancel, but generally, because adjacent wires are often carrying current in opposite directions, the EMF produced tends to be cancelled. Inside residences, typical baseline 60-Hz magnetic fields (far away from appliances) range from 0.5 to 5.0 mG. EMF in the home arise from electric appliances, indoor wiring, grounding currents on pipes and ground wires, and outdoor distribution or transmission circuits. All these separate power-line magnetic fields add or subtract from the steady field of the earth (570 mG), so that the sum total magnetic field in the home has both a steady part and a time-varying part.

Higher 60-Hz magnetic field levels are found near operating appliances. For example, can openers, mixers, blenders, refrigerators, fluorescent lamps, electric ranges, clothes washers, toasters, portable heaters, vacuum cleaners, electric tools, and many other appliances generate magnetic fields of size 40 to 300 mG at distances of 1 foot (NIEHS, 2002). Magnetic fields from personal care appliances held within ½ foot (*e.g.*, shavers, hair dryers, massagers) can produce 600 to 700 mG. At school and in the workplace, lights, motors, copy machines, vending machines, video-display terminals, pencil sharpeners, electric tools, and electric heaters are all sources of 60-Hz magnetic fields.

2.4 State, National, and International Guidelines for EMF Are Available

The US has no federal standards limiting occupational or residential exposure to 60-Hz EMF. Table 2.1 shows guidelines suggested by national and world health organizations. The levels shown on Table 2.1 are designed to be protective against any adverse health effects. The limit values should not be viewed as demarcation lines between safe and dangerous levels of EMF, but rather, levels that assure safety with an adequate margin of safety to allow for uncertainties in the science. Table 2.2 lists guidelines that have been adopted by various states in the US. State guidelines are not health-effect based, and have been typically adopted to maintain the *status quo* for EMF on and near transmission line ROWs.

Table 2.1 60-Hz EMF Guidelines Established by Health and Safety Organizations

Organization	Magnetic Field	Electric Field
American Conference of Governmental and Industrial Hygienists (ACGIH) (occupational)	10,000 mG[a] 1,000 mG[b]	25 kV/m[a] 1 kV/m[b]
International Commission on Non-Ionizing Radiation Protection (ICNIRP) (general public, continuous exposure)	**2,000 mG**	**4.2 kV/m**
Non-Ionizing Radiation (NIR) Committee of the American Industrial Hygiene Assoc. (AIHA) endorsed (in 2003) ICNIRP's occupational EMF levels for workers	4,170 mG	8.3 kV/m
Institute of Electrical and Electronics Engineers (IEEE) Standard C95.6 (general public, continuous exposure)	9,040 mG	5.0 kV/m
UK, National Radiological Protection Board (NRPB) [now Health Protection Agency (HPA)]	2,000 mG	4.2 kV/m
Australian Radiation Protection and Nuclear Safety Agency (ARPANSA), Draft Standard, Dec. 2006[c]	3,000 mG	4.2 kV/m
Comparison to ***steady*** [see text] *(DC) EMF, encountered as EMF outside the 60-Hz frequency range:*		
Earth's magnetic field and atmospheric electric fields, steady levels, typical of environmental exposure[d]	550 mG	0.2 kV/m up to > 12 kV/m
Magnetic Resonance Imaging Scan, static magnetic field intensity[d]	20,000,000 mG	–

Notes:

(a) The ACGIH (2010a) guidelines for the general worker (ACGIH, 2010b, p124-127).

(b) The ACGIH (2010a) guideline for workers with cardiac pacemakers (ACGIH, 2010b, p124-127).

(c) ARPANSA (2006, 2008).

(d) These EMF are steady fields, and do not vary in time at the characteristic 60 cycles-per-second that power-line fields do. However, if a person moves in the presence of these fields, the body experiences a time-varying field.

Table 2.2 State EMF Standards and Guidelines for Transmission Lines

State	Line Voltage (kV)	Electric Field (kV/m)		Magnetic Field (mG)	
		On ROW	Edge ROW	On ROW	Edge ROW
Florida[a]	69 – 230	8.0	2.0[b]		150
	500	10.0			200, 250[c]
Massachusetts			**1.8**		**85**
Minnesota		8.0			
Montana		7.0[d]	1.0[e]		
New Jersey			3.0		
New York[c]		11.8 11.0[f] 7.0[d]	1.6		200
Oregon		9.0			

Notes:

ROW = right of way; mG = milligauss; kV/m = kilovolts per meter.

(a) Magnetic fields for winter-normal, *i.e.*, at maximum current-carrying capability of the conductors.

(b) Includes the property boundary of a substation.

(c) 500 kV double-circuit lines built on existing ROWs.

(d) Maximum for highway crossings.

(e) May be waived by the landowner.

(f) Maximum for private road crossings.

Sources: NIEHS (2002); FLDEP (2008).

3 Modeled Magnetic Fields

3.1 Software Programs Used for Modeling EMF

We used the FIELDS computer program, designed by Southern California Edison, to calculate magnetic field strengths from the proposed lines at cross-sections perpendicular to the lines as a function of voltage, current, and distance. This program operates using Maxwell's equations, which accurately describe the laws of physics as they apply to electricity and magnetism. Modeled fields using this program are both precise and accurate for the input data utilized. Results of the models have been checked extensively against each other and against other software (*e.g.,* "CORONA" from the Bonneville Power Administration, US Dept. of Energy) to ensure that the implementation of the laws of physics are consistent. In these validation tests, program results for EMF were found to be in very good agreement with each other.

3.2 Power-Line Flows

Magnetic fields produced by the proposed lines were modeled using line loadings communicated by Eversource. The current per phase satisfies the relationship:

(Eq. 3.1)

$$S = \sqrt{3} \times V \times I_{phase}$$

where:

$\boldsymbol{S}$ = the power in kilovolt-amps (kVA)
$\boldsymbol{V}$ = the line voltage in kilovolts (kV)
I_{phase} = the current per phase in amps (A).

Thus, the current per phase conductor is:

(Eq. 3.2)

$$I_{phase} = \frac{S}{\sqrt{3} \times V}$$

Real power is given in megawatts (MW) [***P***], and apparent power in megavolt-amps (MVA) [*S*].[1] To convert between power quoted in megawatts to megavolt-amps, one must divide by the power factor.

Electric current values provided by Eversource are summarized in Table 3.1 (Velez, 2015). Eversource determined these currents by power-flow modeling for the future year 2018 assuming that all of the other Greater Boston solution projects were complete, that all lines are in service, and using the peak-load generation dispatch from the Greater Boston needs assessment studies that would produce the highest current flow on the existing Line 211-514.

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[1] MVA is apparent power and is the vector sum of real (active) and imaginary (reactive) power. MW and MVA are not the same unless power factor = 1.0, which in a practical AC circuit is generally not the case.

Table 3.1 Electric Currents for Proposed Project

Existing Line Only, 2018 Projected Load			
Transmission Line	**Projected (2018) Future Average Load Current (Amps)**	**Projected (2018) Future Peak Load Current (Amps)**	**Direction of Current**
Existing 211-514x (115-kV line)	155	840	Woburn to Mystic
Existing Line and New Line, 2018 Projected Load			
Transmission Line	**Projected (2018) Future Average Load Current (Amps)**	**Projected (2018) Future Peak Load Current (Amps)**	**Direction of Current**
Existing 211-514x (115-kV line)	124	497	Woburn to Mystic
Proposed 211-514y (115-kV line)	162	704	Woburn to Mystic

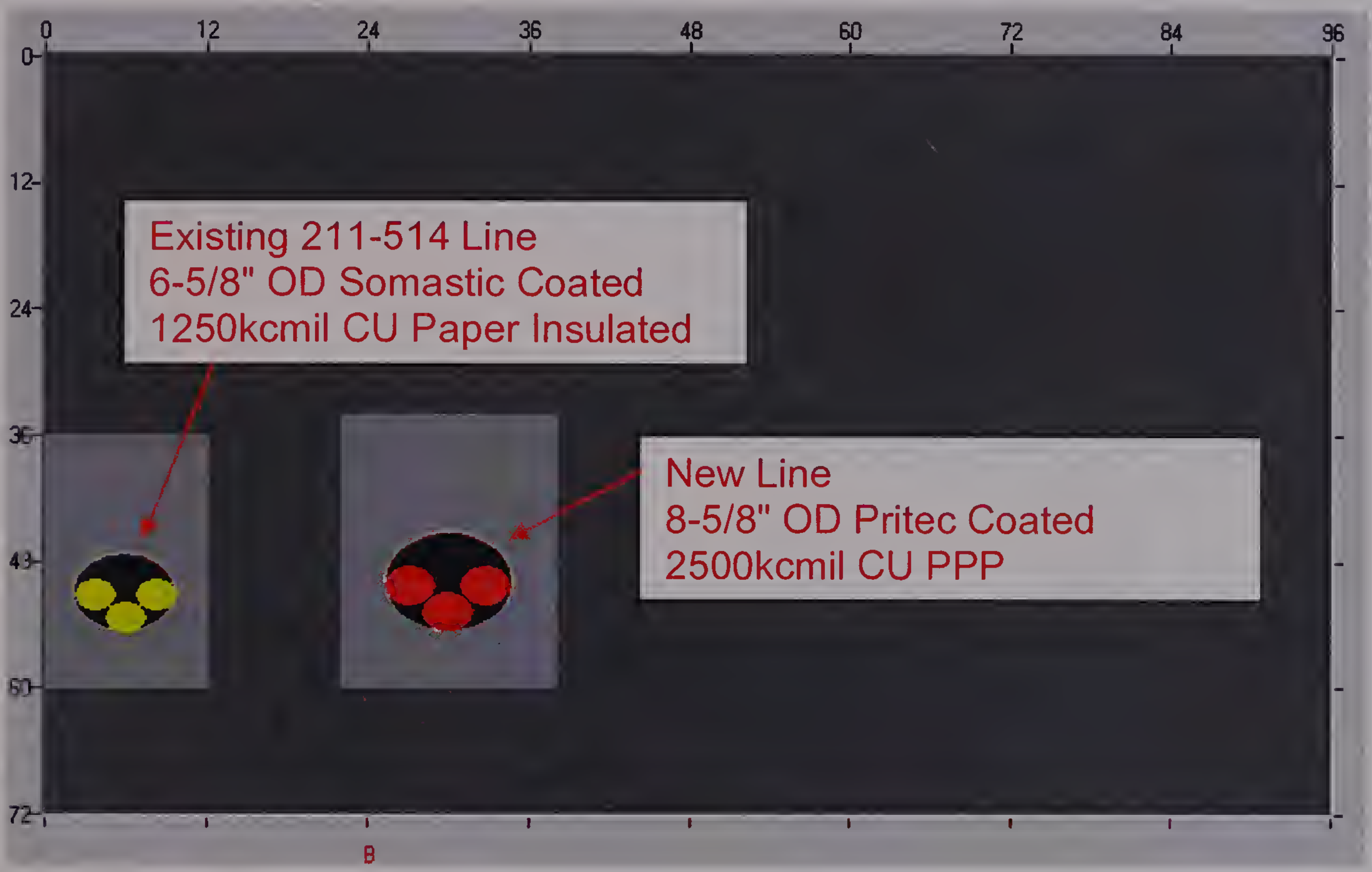
3.3 EMF Model for the Proposed Transmission and Distribution Lines

EMF modeling of the proposed underground lines included calculation of magnetic fields levels expected to exist 3 feet above the ground surface for the peak 2018 loading on the lines in both scenarios described above (with and without the new 115-kV line). We modeled a cross-sectional view of magnetic field strength as a function of distance perpendicular to the direction of current along a segment of the route where power lines are parallel and straight. Since aboveground electric fields from underground circuits are zero due to the shielding effects of the metal pipe and the earth, no electric field modeling was needed.

Eversource provided Gradient with proposed configuration schematics as well as circuit specifications. (Eversource, 2015; select drawings are provided as Appendix A).

The model loadings on the two lines are shown in Table 3.1 and discussed in Section 3.2. The existing 115-kV line consists of three 115-kV 1250-kcmil HPFF cables arranged in a triangular configuration within a 6-5/8" steel pipe. The proposed 115-kV line consists of three 115-kV 2500-kcmil HPFF pipe type cables arranged in a triangular configuration within a 8-5/8" steel pipe. In the scenario containing both existing and proposed pipes, the center-to-center distance between the two pipe ducts is 12.083 feet (Velez, 2015). All circuits are at an approximate depth of 4.5 feet (Velez, 2015). Figure 3.1, provided by Eversource, shows a cross-section of the typical offset between the existing and proposed lines (Eversource, 2015).

The ferromagnetic steel pipes enclosing each set of transmission line phase conductors considerably attenuate the magnetic field that would be produced by the phase conductors alone, in the absence of the steel pipe. Estimates of shielding efficiency by ferromagnetic materials suggest that for bundled 3-phase cables, surrounding ferromagnetic material reduces the magnetic fields by 25- to 30-fold below what is calculated for the unshielded cables, although shielding factors of about 100 have been achieved in some cases. Anticipated field values are therefore at least ten times smaller than the values calculated for the transmission lines without taking into account shielding effects (Xu and Yang, 1996; EPRI, 1993; EPRI and HVTRC, 1994). This ten-fold attenuation is therefore included in our models.



Existing 211-514 Line
6-5/8" OD Somastic Coated
1250kcmil CU Paper Insulated

New Line
8-5/8" OD Pritec Coated
2500kcmil CU PPP

Figure 3.1 Schematic of the Configuration for the Existing and Proposed Lines. The *x-y* coordinate system origin is at the street surface in the upper left corner of the figure. The conductor locations shown are illustrative, and the figure is not to scale. Typical depth variations created during installation would have a small effect on the calculated magnetic field values.

3.4 EMF Modeling Results

Figure 3.2, below, shows the calculated magnetic field for 2018 average loading conditions at 3 feet above ground surface (including the 10-fold magnetic field attenuation by the steel pipe) for the existing line only (green) and the configuration containing the existing and proposed lines (pink). Each gray diamond represents the location of a phase conductors present in the configuration containing only the existing transmission line, and each black diamond represents the location of a phase conductor present in the configuration containing both the existing and proposed transmission lines. As shown in the figure, the modeled magnetic fields due to the existing line only reach a maximum at 0.76 mG and fall to 0.10 mG a distance of 20 feet laterally on either side of the centerline of the circuit. The modeled magnetic fields due to the existing line and proposed lines together reach a maximum at 0.83 mG and fall to 0.13 mG at x=0 and 0.17 mG at x=50.

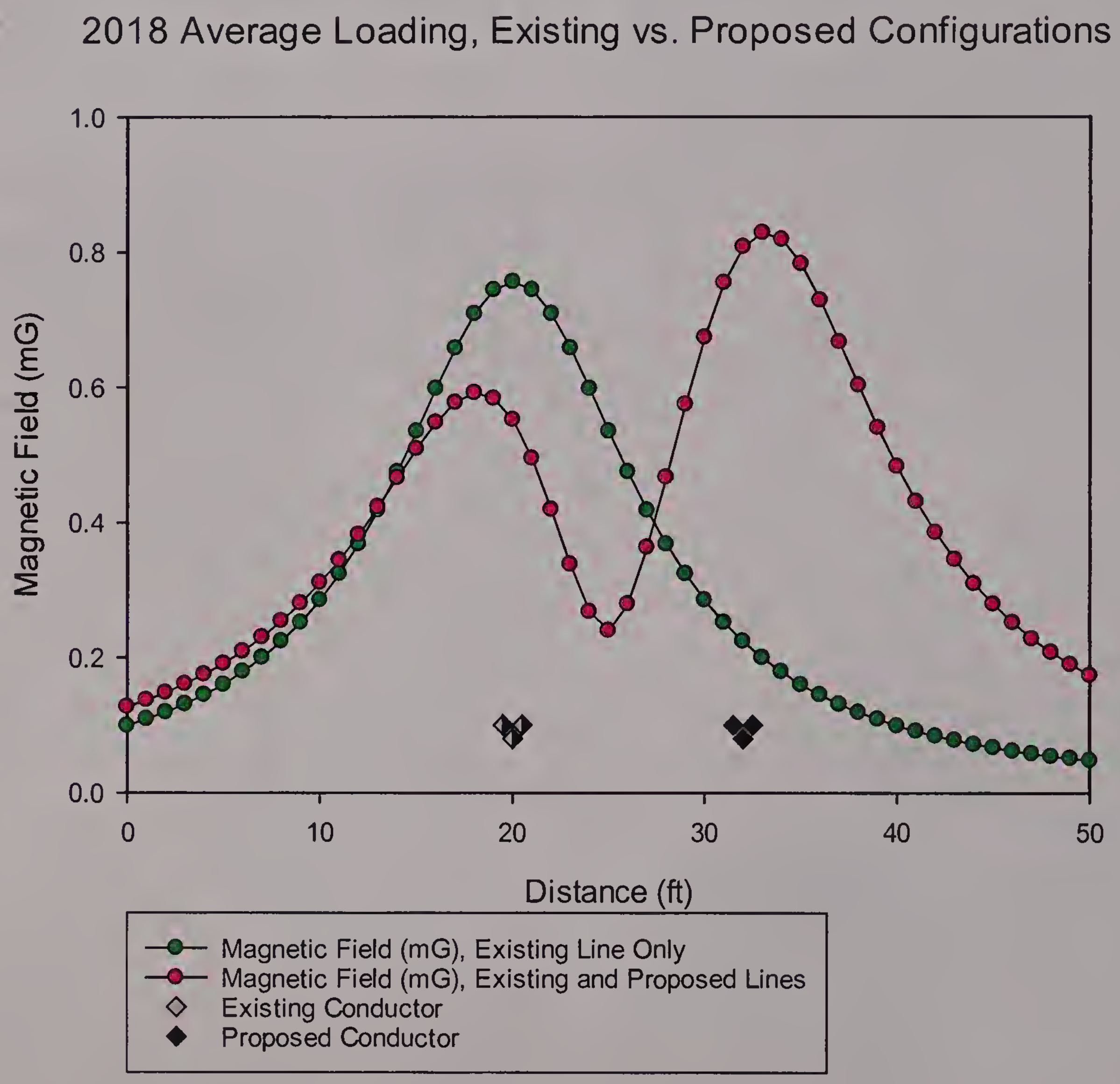


Figure 3.2 Magnetic Field Values for 2018 Average Loading Conditions, Existing vs Proposed Configurations. The maximum magnetic field value for the existing line only is 0.76 mG, located at *x*=20. The magnetic field values drop rapidly with lateral distance from the lines, falling to 0.10 mG at 20 feet to either side of the centerline of the existing conductors. The maximum magnetic field value for the configuration containing both lines is 0.83 mG, located at *x*=33. The magnetic field values drop rapidly with lateral distance from the lines, falling to 0.13 mG at x=0, and 0.17 mG at x=50.

Figure 3.3, below, shows the calculated magnetic field for 2018 peak loading conditions at 3 feet above ground surface for the existing line only (green) and the configuration containing the existing and proposed lines (pink). Each gray diamond represents the location of a phase conductors present in the configuration containing only the existing transmission line, and each black diamond represents the location of a phase conductor present in the configuration containing both the existing and proposed transmission lines. As shown in the figure, the modeled magnetic fields due to the existing line only reach a maximum at 4.10 mG and fall to 0.54 mG a distance of 20 feet laterally on either side of the centerline of the circuit. The modeled magnetic fields due to the existing line and proposed lines together reach a maximum at 3.61 mG and fall to 0.52 mG at x=0 and 0.74 mG at x=50.

The modeled magnetic field values all fall below the Massachusetts guideline for magnetic field values (85 mG, see Table 2.2).

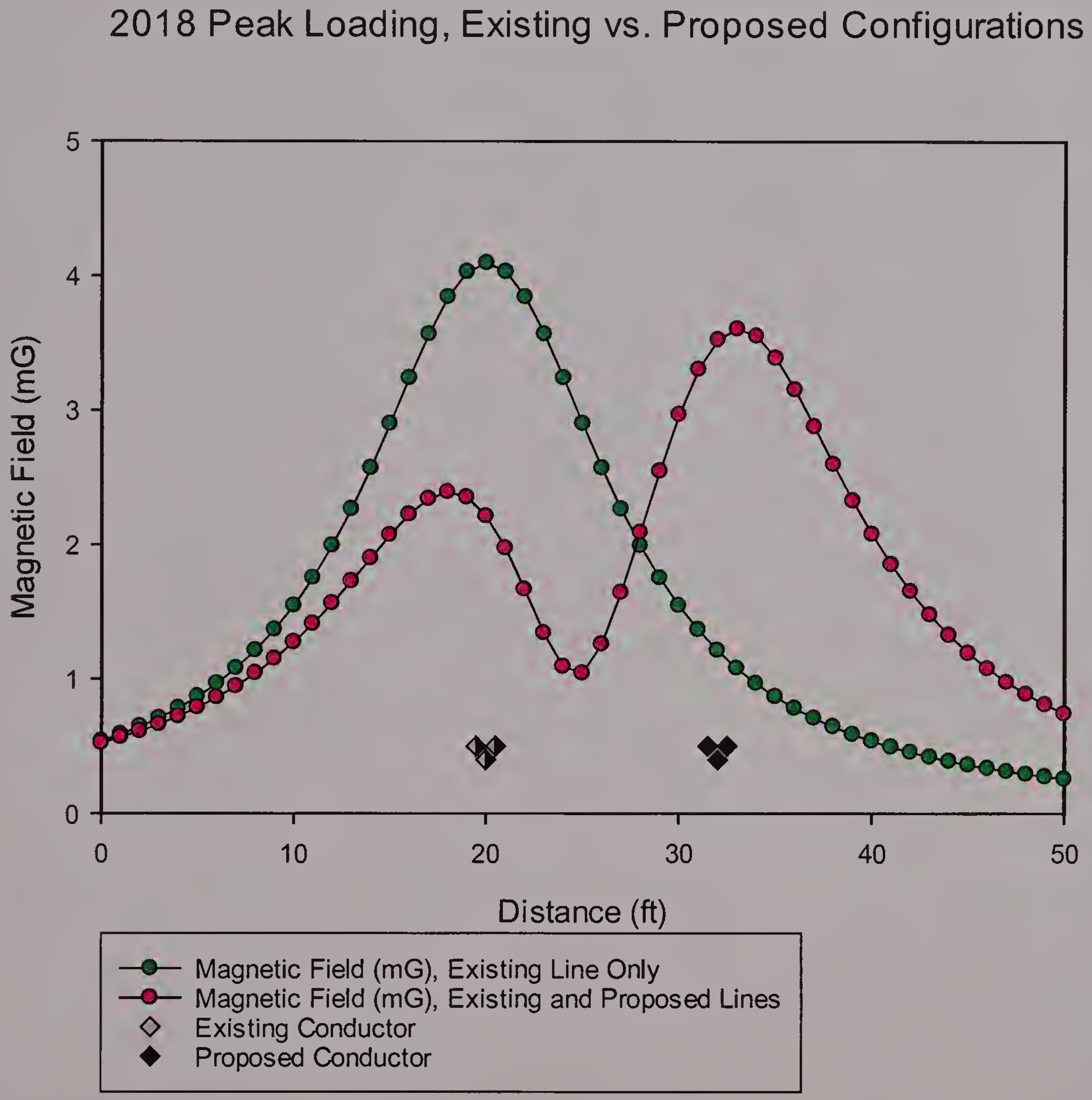


Figure 3.3 Magnetic Field Values for 2018 Peak Loading Conditions, Existing vs Proposed Configurations. The maximum magnetic field value for the existing line only is 4.10 mG located at x=20. The magnetic field values drop rapidly with lateral distance from the lines, falling to 0.54 mG at 20 feet from the centerline of the conductors. The maximum magnetic field value for the configuration containing both lines is 3.61 mG, located at *x*=33. The magnetic field values drop rapidly with lateral distance from the lines, falling to 0.52 mG at x=0, and 0.74 mG at x=50.

4 Conclusions

Gradient calculated the 3 feet above ground-surface magnetic field levels projected to exist above the existing and proposed configurations of the Mystic-to-Woburn project. Table 4.1, below, summarizes the magnetic field results for the EMF modeling. All fields represent modeled values for the projected peak and average operational line loads (2018). Because all circuits are underground, electric fields associated with all lines are zero.

Table 4.1 Modeled Magnetic Fields 3 Feet Above Ground Surface

Scenario	Maximum Magnetic Field (mG)
Existing Line Only, Peak Load	4.10
Existing Line Only, Average Load	0.76
Existing and Proposed Lines, Peak Load	3.61
Existing and Proposed Lines, Average Load	0.83

Table 4.1 demonstrates that the maximum magnetic field levels predicted along the underground routes of the existing and proposed lines fall well below accepted health-based guidelines for allowable public exposure to magnetic fields (2,000 mG) (ICNIRP, 2010). In addition, all field levels along the distribution line routes, including directly overhead, fall below the Massachusetts ROW-edge magnetic-field guideline of 85 mG (see Table 2.2). Overall, there is no expectation of adverse health effects due to the EMF impact from the proposed underground circuit project.

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